California Solar Initiative.

For Metering, Monitoring and Reporting Market Photovoltaic Systems in California.

Final Report to Southern California Edison

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1. Introduction

KEMA, Inc. (KEMA) is pleased to submit this report on the California Solar Initiative (CSI) Metering & Performance Monitoring Market Assessment to Southern California Edison (SCE). The primary purpose of this project, as stated in the RFP statement of work (SOW), is to assess the metering, monitoring, and reporting market for photovoltaic (PV) systems in California and to deliver a series of reports to document the results.

Although the original request for proposal (RFP) was submitted on behalf of the California Solar Initiative (CSI) program administrators (PAs), Southern California Edison (SCE), Pacific Gas and Electric (PG&E), and California Center for Sustainable Energy (CCSE), SCE issued the purchase order and entered into a contract with KEMA to perform the work as defined in the SOW and to manage the project on behalf of all of the PAs.

Following the award of the contract to KEMA, the California Public Utilities Commission (CPUC) asked SCE if the contract with KEMA could be modified to include working with the CSI Metering Subcommittee's 5% Meter Certification Working Group to write the *Inverter Integral 5% Meter Performance Specification.* Writing the meter specification was included in the Research Plan, which KEMA submitted to SCE on December 24, 2008.

The Research Plan was the project's first deliverable and a prerequisite for performing any of the research tasks defined in the SOW. The Research Plan was approved by SCE on January 14, 2009, at which time the research tasks of the project commenced. The research plan is included in this report as Appendix A.

The second deliverable was the 5*% Meter Performance Specification*, which was finalized in cooperation with the 5% Meter Certification Working Group and delivered to SCE on March 25, 2009. The specification is included in this report as Appendix B.

The following report, in Sections A through H, represents the culmination of KEMA's research efforts to address the specific requirements of the original SOW.

2. Executive Summary

KEMA divided the major project tasks into four basic categories and assigned subject-matter experts with specific knowledge and expertise to concentrate their efforts within those categories most closely matching their areas of expertise. The four major categories are:

- Survey and evaluation of existing CSI products and services
- AMI integration with CSI
- Market assessment of solar metering
- Meter specification.

2.1 Survey and Evaluation of Existing CSI Products and Services

This category includes sections A, B, D, and E. KEMA developed a comprehensive 25-page survey to collect the information needed for these sections from all 37 of the existing performance monitoring and reporting service (PMRS) providers and performance data providers (PDPs) currently registered with the California Energy Commission (CEC). All ten PDPs are also PMRS providers. A copy of this survey is provided in Appendix C.

The survey requested detailed information about product and service offerings, warranties, and costs for the various product and service offerings. Thirteen of the survey recipients (35 percent) provided all of the information requested. One of the concerns expressed by those surveyed was their reluctance to divulge competitive or proprietary information. Follow-up calls were made to the non-respondents and those who provided incomplete information. These calls yielded some additional information, but a number of the survey recipients expressed reluctance or unwillingness to provide the requested information.

Product and service offerings cover a wide range, as does the cost data that KEMA was able to obtain. Cost data was the most difficult to collect, as is discussed in the report. In order to protect the confidentiality of the information provided, most of the data is presented generically by vendor number rather than vendor name. Solar thermal systems are not included in the survey, because not a single manufacturer of a solar thermal unit or metering device has applied for inclusion on the CSI listing to date.

In Section A, survey results were separated into five categories: 1) components, 2) standards, 3) communication networks, 4) equipment warranties, and 5) meter costs.

In Section B, survey results were separated into three categories: 1) cost ranges, 2) PMRS/PDP provider types, and 3) installation and verification services. Due to the variations in service offerings, costs vary dramatically.

Simple block diagrams were obtained directly from PMRS/PDP providers and also from the public domain. These are presented in Section D to illustrate the various types of PMRS/PDP systems in use.

Two main concerns were raised by the respondents:

- The true value of PMRS is not being realized within the current CSI program structure, particularly for monitoring conditions such as system degradation.
- The PMRS cost cap causes undue traffic for PMRS providers. PMRS costs for most systems qualifying for EPBB incentives will exceed the cost cap. Supporting this is the fact that all but 17 of the EPBB systems installed exceeded the cost cap.

2.2 AMI Integration with CSI

One of the goals of this project is to consider how the available metering technology for solar systems may integrate with advanced metering infrastructure (AMI) metering technology. AMI “smart meters” offer several advantages for solar PV systems:

- The ability to store interval data for multiple intervals per day—where typical intervals may be 15 minute, 30 minute, or an hour—with meter reading data collected automatically one or more times per day.
- The ability to act as a “net meter” by storing energy delivered to the grid separately from energy consumed from the grid.
- Two-way communications with the meter to facilitate meter reading, meter firmware updates, and communications with an home area network (HAN).

Section C analyzes the data transfer requirements and describes the processes currently in use as well as the new EDI 867 standard. Although CSI systems do not currently qualify for tradable renewable energy credits (RECs) for the Western Renewable Energy Generation

Information System (WREGIS), there is pending legislation that may eliminate that restriction in the future. As a result, KEMA considered the requirements for certifying RECs, in the process of analyzing and documenting data requirements.

Section F provides an assessment of how AMI and solar systems could be best integrated through the use of common technologies and/or standardized data transfer requirements. Meter data for each of the solar sites monitored by PMRS/PDP is required to provide data to each administrator through EDI 867 protocols once a month to facilitate calculating PBI rebates for a five-year period. Currently, each administrator is setting up a different process to collect this data. SCE plans to receive the data and manage incentive payment processing through their internal resources, while PG&E and CCSE will outsource this process. PMRS/PDPs are required to follow each administrator's rules and processes. Common technologies will be even more important when CSI incentive payments (EPBB and PBI) end and billing depends upon net metering only.

2.3 Market Assessment of Solar Metering

Although a separate survey was created for market research sections G and H, these sections also benefited from information collected by the PMRS/PDP survey. A copy of the market research survey is included in Appendix F.

To compare and contrast metering requirements of solar energy incentive programs, KEMA considered the 15 PV incentive programs in the United States (U.S.) and around the world that were most relevant in scope and purpose to the CSI program. For each program, KEMA conducted a review of all publicly available information, including information gathered from the Database of State Incentives for Renewable Energy (DSIRE) and from the websites of these programs. When possible, KEMA interviewed program staff to confirm and obtain additional information. Appendix G includes the list of program staff KEMA interviewed during this research.

Metering requirements vary from program to program depending on system size, system accessibility, treatment of RECs, and mostly by incentive structure. Most of the programs reviewed require monitoring, even for capacity-based incentives like EPBB. There are two types of metering that are relevant to solar incentive programs: net metering and performance metering. Section G discusses these two types of metering in detail.

Section H provides a comprehensive assessment of current market challenges and drivers. The results of the surveys were summarized into the following categories:

- Market drivers
- Market challenges
- PMRS products needs and gaps
- Product and technology trends
- Technical challenges.

The primary PMRS market driver is to optimize solar system production; this is especially important for PPA providers whose revenue is tied to system production. Interview respondents revealed mixed feelings about how incentive program requirements affect the PMRS market. The CSI requires PMRS and data reporting for Performance-Based Incentive (PBI) payments, and it would be expected that CSI is the main driver of PMRS purchases in California. However, the interviews revealed that CSI does not seem to be a major driver for the PMRS market.

Most interviewees believe solar integration with the smart grid will occur in the near future—within the next 10 years, while some think integration will occur within the next 2-5 years. Ultimately, solar and smart-grid integration depends on the focus of the utilities.

The lack of data standardization and specification of minimal monitoring requirements are challenges that affect all emerging technologies. All survey respondents favored adopting some standards to ensure quality and consistency. The main technical challenge the industry faces is lack of standards, including equipment, safety, and performance standards, and smart-grid specifications.

2.4 Meter Specification

Following acceptance of the research plan, the project's first deliverable was the meter specification, which is attached to this report as Appendix B. The specification is titled, "*Inverter Integral 5% Meter Performance Specification,"* and was developed in cooperation with the CSI Metering Subcommittee's 5% Meter Certification Working Group. The specification only applies to meters that are an integral part of inverters used in systems that qualify for EPBB incentives. The specification is based upon existing ANSI C12.1, IEEE 1541, and UL1741 specifications to the extent that they apply to the integrated meters. The specification is expected to become the basis for future testing of these meters by manufacturers as well as independent testing labs. Currently, the accuracy of these meters is self-certified by the manufacturer. In January 2010, the meters will require independent certification.

2.5 CSI Program Recommendations

Several recommendations for improvement to the CSI have been developed through this study. Many of these recommendations are derived from data contained within study sections; therefore, a comprehensive set of recommendations are provided here rather than throughout the report.

2.5.1 CSI Cost Caps

The current cost cap policy is not working well. Very few systems below 15 kW require PMRS service under the current cost cap. Also, several PMRS providers are upset that customers request cost quotes solely to demonstrate that PMRS service cost would exceed the cost cap. Therefore, it is recommended to either:

- Abolish this service requirement for systems below 15 kW. This would eliminate PMRS cost quote traffic for approximately 98% of systems being installed. Approximately 98% of the systems that have been installed under CSI are below 15 kW
- Make PMRS a requirement for all systems receiving CSI incentive payments

2.5.2 PMRS System Costs

There are many variables to system costs for PMRS service. System output can be monitored through separately installed system output meters or through inverter integral meters. Currently, PMRS systems are only required to monitor system output (kWh) at 15-minute intervals, although many providers offer monitoring for other PV system parameters. Therefore, PMRS costs can vary dramatically. From an evaluation perspective, PMRS costs can be loosely correlated to system size, but the CSI does not request enough information from installers to quantify these costs.

It is recommended that PMRS costs are recorded in the CSI database for each installed system. Other pertinent information that should be included is whether a separate output meter is used or if the PMRS utilizes an inverter integral meter.

2.5.3 Improved Integration of PMRS with the CSI

Discussions with various PMRS providers about the appropriateness of current cost caps yielded feedback recommending elimination of the cost cap and providing better integration between PMRS service with the incentive structure. PMRS service aids system output improvement through feedback on system performance. To date, no known studies have been completed to quantify additional system production as a result of PMRS.

The authors recommend better integration of PMRS service with the incentive structure through:

- Maintaining cost caps as they are, but only for systems above 15 kW, as discussed in the CSI Cost Cap section above.
- Encouraging PMRS implementation by offering a direct incentive of $1,000 for each PMRS system installed.
  - To qualify for this incentive, the PMRS system would need to meet the following requirements:
    - Measure and record system output (kWh) at 15-minute intervals, as is currently required.
    - Include a weather station that records, as a minimum, solar irradiance and back of module temperature.
    - Compare daily system output to its expected output, based on module temperature and solar irradiance. This would require algorithm development for each system, which would include shading factors, determined through use of a solar pathfinder and other known de-rating factors, such as module mismatch, wiring losses, minimum module output, etc. The algorithm would determine minimum expected output for comparison to actual system output.
    - A notification to the system owner when a system's actual output fall below its expected output, so that maintenance or repairs can be made.
    - ,The PMRS would send 15-minute interval data for system output (kWh) and measured values for solar irradiance and back of module temperature to the CSI program administrator on a quarterly basis. Other pertinent data sent to the CSI program administrator would include the date of any notifications of lower-than-expected system performance to the system owner.

Implementation of these recommendations would encourage implementation of PMRS service. It would also provide a database that could be used to determine the actual value of PMRS service in terms of increased system performance.

3. Section A – Hardware and Equipment Review of Industry Solar Projects

3.1 Objectives

In this section, we review metering hardware and equipment currently being utilized for solar projects within California through three discrete tasks including:

- Identifying, describing and assessing of major metering system components
- Describing system hardware components
- Providing written review of metering systems and meter component distributors.

Survey tools were developed to determine the characteristics and functionality of performance monitoring and reporting service (PMRS) and performance data provider (PDP) metering hardware being used in solar projects, which is fairly straight-forward with a few general options available. However, PMRS/PDP systems are not as simple. There is no single architecture being utilized that can be evaluated, so each system requires a brief discussion to be understood and quantified.

3.2 Survey Tools

To identify the major metering components, an on-line survey was developed and loaded into SurveyMonkey, a web-based tool to facilitate survey access. The survey included approximately 30 questions primarily concerning products and services provided by each PMRS/PDP. The survey was designed to solicit open-ended responses about offerings as well as specific responses, which would sometimes include branch logic depending on the response. We have provided a copy of survey questions in Appendix C.

A link to the survey was sent out to all registered PMRS/PDP providers in February 2009. At the time of the survey, there were 37 PMRS providers registered with the California Energy Commission (CEC). Each investor-owned utility (IOU) maintains its own PDP listing; yet each PDP *must* also be a PMRS. There are approximately 10 PDPs registered with the three IOUs. The 37 PMRS providers are listed in Table 3-1.

Table 3-1: Registered PMRS/PDP Providers

Company	Website
Act Solar, Inc.	www.actsolar.com
Agilewaves	www.agilewaves.com
Applied Power Technologies (APT)	www.apt4power.com
Chevron Energy Solutions	www.chevronenergy.com
CSS-Technologies	www.css-technologies.com
DEB Solar	www.debsolar.com
Desert Solar	www.desertsolar.org
Draker Laboratories, Inc.	www.drakerlabs.com
Energy Recommerce, Inc.	www.energyrecommerce.com
Enerlon	www.enerlon.com
EnFlex Corp	www.enflex.net
Enphase Energy, Inc.	www.enphaseenergy.com
E-Village Solar	www.evillagesolar.com
Fat Spaniel Technologies, Inc.	www.fatspaniel.com
Glu Networks, Inc.	www.glunetworks.com
ICP Solar Technologies Inc.	www.sunsei.com
Locus Energy	www.locusenergy.com
metrocontrol GmbH	www.meteocontrol.com
natcon7	www.solar.natcon7.com
N2 Electric, Inc.	www.n2electric.com/
Noveda Technologies	www.noveda.com
Power Nab	www.powernab.com
PV Powered	www.pvpowered.com
Pyramid Solar, Inc.	www.pyramidsolar.com
Radback Energy Services	www.radback.com
Recurrent Energy, Inc.	www.recurrentenergy.com
Satec	www.oksatec.com
Solar City	www.solarcity.com
Solar Engineering Industries, Inc.	www.solarengineeringinc.com
Solar Integrated Technologies	www.solarintegrated.com
Solectria Renewables, LLC	www.solren.com
Sunpower	www.sunpowercorp.com
Thompson Technology Industries, INC.	www.thompsontec.com
Tilt Solar LLC	www.tiltsolar.com
Trimark Associates	www.trimarkassoc.com
Viasyn, Inc.	www.viasyn.com
Xslent Energy Technologies	www.xetenergy.com

The CEC contracted KEMA to maintain the PMRS listing, so our contact information database was used to contact each provider.

During the week of February 24, 2009, each provider who did not answer the survey was contacted by phone to check survey completion status. There were six existing providers who had new employee contacts not listed in KEMA's database, so contact information was updated. Some highlights about response rates include:

- 13 of the 37 providers (35 percent) provided legitimate responses to the survey after all follow-up contacts were made.
  - One of the 13 did not fill out the online survey, but provided answers over the phone.
  - Nine of the 13 respondents provide both PMRS and PDP services.
- Eight additional providers logged onto the survey and provided either very little or no information. These are not included in the survey responses.
  - One provider is also an inverter manufacturer and mentioned they supply free PMRS services for customers who purchase their products—interface occurs through an inverter integral meter. Very little additional information was provided, and many of the survey questions did not apply to this vendor.
  - One provider responded that the survey was too detailed, and they were not willing to spend time filling it out.
  - One provider responded that their PMRS service is only for photovoltaic (PV) systems they install and is not available for resale. No actual product definition was provided, so this response was not included in the evaluation.
  - Five providers simply logged onto the survey and either entered their name or gave a brief, overall description of their service, and did not continue the survey.

Some general feedback concerning the survey was provided.

- Several providers voiced concerns over publication of their pricing schedules. They did not want anyone expecting any published pricing schedules in a general report to be honored. Also, since each of these providers offers more services than output monitoring, they do not want any potential customers to compare their services based on a published pricing schedule. As a result, survey outcomes are presented in a very generic fashion without provider names included.
- Some providers expressed concern over sharing any pricing information at all. At least two providers (spoken to over the phone) expressly stated they would not give any pricing information due to the competitive nature of their business.
- There were two main concerns raised regarding the current structure of the CSI program.

- Many felt that the true value of the PMRS service was not being realized. Some providers routinely offer system monitoring services to pinpoint any performance degradation in the system. The value of this service is not being realized within the current CSI program structure, according to three different providers, since the incentive structure does not include this value directly. For performance-based incentive (PBI) systems, the extra value is realized through increased production, and therefore increased incentive payments. For expected performance-based buydown (EPBB) systems, all incentive is paid upfront, so the value to the customer for optimum PV production is less. To date no known studies have been completed that quantify the value (increased energy production) of these additional services.
- The PMRS service cost cap causes undue traffic for PMRS providers. A quote from a PMRS must be provided showing the cost to exceed the cap, as defined in the CSI Handbook, to waive the PMRS requirement. Providers receive requests for quotes solely for the purpose of having the cost cap waived. Feedback indicated that PMRS service for most systems qualifying for EPBB incentives will exceed the cost cap; though not a single provider was able to give a more appropriate cost cap. Recommendations included
    - Have all systems PBI based
    - Restructure the incentives such that PMRS service, with its added value, is compensated for directly.

3.3 Background and Significance

The requirement for a system output meter has been in place since 1998, carrying over from California's legacy Emerging Renewables Program (ERP). Over the years, the types of metering and information systems used with PV systems have changed dramatically. Many new output metering types now exist, which have been reviewed by KEMA and added to the CEC's list of eligible equipment. When the pilot (PBI system was added to the legacy ERP, a new requirement was added to include revenue-grade output meters to qualify for the incentive.

Recently, an option to include solar thermal systems—electric generation and heat generation (for electric use avoidance)—has been added to the CSI Handbook. Heat generation systems require a qualified British thermal unit (Btu) meter to measure output and calculate the electric use avoidance. To date, no manufacturers of solar thermal units or metering devices have applied for inclusion on the CSI listing. As a result of this, solar thermal monitoring systems are not included in this survey.

3.4 Primary Tasks and Research Methods

The results of the online survey tool were used to inform several sections of this study. Results relevant to performing hardware and equipment review include:

3.4.1 Identification, Description and Assessment of Major System Components

The survey obtained details of each PMRS/PDP system, such as testing & certification, communication devices used, applicable warranties, required maintenance, and system costs including:

- The various components of PMRS/PDP systems, how they are interconnected, and types of meters used
- Testing and certification entities, and practices and standards
- Compatible communications networks for each applicable element
- Cost ranges and typical or targeted costs for systems and/or components. (Costs for meters only are provided in this section; other costs are included in Section B.)
- Information on equipment warranties. (System warranty information is included in Section B).

3.4.2 Detailed Description of System Hardware Components

The survey captured information on system hardware components including:

- Detailed descriptions of system components which were developed into a database.
- Costs of systems' elements were researched. In most cases, providers utilize their proprietary hardware systems for most data monitoring (reported costs for equipment and installation are listed in Section B). Meters are not typically proprietary to the specific PMRS/PDP, and were provided by the manufacturer. Costs for these meters were researched through web searches or though direct contact with distributors.

3.4.3 Written Review of Meter and Meter Component Distributors

The CSI listing of approved meters was utilized to determine other meter distributors and their product offerings. KEMA maintains the CSI meter listing and has distributor/manufacturer information from their application for inclusion on the listing. Further information on these manufacturers/distributors meters were obtained through web searches.

3.4.4 Research Results

An overview of research results relevant to this section include:

- Components
- Standards
- Communication networks
- Equipment warranties
- Meter costs.

3.4.4.1 Components

Metering components used by the various PMRS providers and PDPs include meters, data loggers, internet gateways, power-quality monitors, data collection "computers," and weather monitoring equipment (solar irradiance and temperature sensors and wind speed anemometers). Many of these components are proprietary systems developed by the particular PMRS/PDP; some components are "off-the-shelf." Others are systems developed by various inverter manufacturers and utilized by the PMRS/PDP. Two PMRS providers are also inverter manufacturers and provide communication gateways that interface with the metering device internal to their inverter.

Providers typically sell a system and not a series of components, so items like compatible communication networks, warranties, and costs are for the system and not for individual components.

It has been very difficult to obtain a detailed PMRS/PDP cost breakdown of various components in use. Some manufacturers will not disclose any cost information; others will give general costs for installation of a system. For hardware components other than meters, a vendor trade name or proprietary system has been provided in most cases. In other words, the original equipment manufacturer (OEM) make and model information is not included. Costs for system installation have been provided in Section B.

3.4.4.2 Standards

Metering devices for PBI systems are certified to American National Standards Institute (ANSI) C12.20. Metering devices used for EPBB systems are either taken from the CSI metering list (manufacturer self-certified to +/- 5 percent accuracy) or tied into the metering device of the inverter. In some cases, the inverter manufacturer has developed a system to record the output of the internal meter (non-revenue grade), and the PMRS will utilize this system.

Agencies or Nationally Recognized Test Labs (NRTLs) qualified to certify products to ANSI C12 accuracy standards are included in the federal Occupational Safety and Health Administration (OSHA) listing.[1] The following NRTLs have been certified to OSHA standards to certify products to ANSI C12 accuracy:

- MET Laboratories, Inc. (MET).
- TUV Rhineland North America, Inc. (TUV)
- Underwriters Laboratories, Inc. (UL).

There are several European labs that certify metering products to International Electrotechnical Commission (IEC) standards, which have very similar (if not identical) accuracy requirements as ANSI standards. Most of these certifications are performed by KEMA, Inc. in the Netherlands and TUV Rhineland in Germany.

3.4.4.3 Communication Networks

There is a mix of hard-wired and wireless communication networks in use. For wireless communication, the only network in use is cellular. For hard-wired communication, most manufacturers use Ethernet, but some use broadband connections. See Section F of this report for a discussion of communication network technologies, including the advantages and disadvantages of each.

[1] http://www.osha.gov/dts/otpca/nrtl/index.html

3.4.4.4 Equipment Warranties

Warranties offered between the different providers vary considerably. The PBI program carries a five-year requirement, so most systems are warranted for five years. One provider offers a 15-year limited warranty, but this provider is an inverter manufacturer, with the warranty covering the inverter. The CSI Handbook requires a 10-year warranty for inverters, so meters integrated into the inverter must be warranted for 10 years minimum. Some other components carry manufacturer equipment warranties, which are typically less than five years.

3.4.4.5 PMRS/PDP Survey Responses

Outcomes of the survey relevant to this section are included in Table 3-2.

In some cases, a particular question asked will not apply to a specific component; these are listed as “NA” (Not Applicable). Also, in some cases a particular question was not answered; these are listed as “NR” (No Response).

Table 3-2: PMRS/PDP Component Offerings

Vendor	Business Model	Component	Testing and certification requirements	Warranties provided	Comm Networks
1	PMRS/PDP Services Building Energy Use Weather Conditions	Vendor specific data collection computer	none	NR	RS-485 communication within the PV site over wired bus, or for physically large sites, a radio link. Customer provides internet connection for data upload.
		Schneider/SquareD ION 6200 meter	ANSI C12.20 Factory calibration report	NR	
		GE kv2c Watthour meter	ANSI C12.20 Factory calibration report	NR	
		Vendor specific weather station	none	NR	
2	PMRS Services Building Energy Use	Vendor specific Revenue Meter, Power Quality Monitor, Fault Recorder, Data Logger	UL Certified, IEC62053-22, IEC62052-11	3 years	NR
		Vendor specific Revenue Meter, Power Quality Monitor, Data Logger	ANSI C12.20 –1998, UL Certified, IEC62053-21, IEC62053-22, IEC62052-11	3 years	NR
		Vendor specific Revenue Meter, Harmonics Monitor, Data Logger	ANSI C12.20 –1998, UL Certified, IEC62053-21, IEC62053-22	3 years	NR
		Vendor specific Revenue Meter, Optional Harmonics Monitor	ANSI C12.20 –1998, class 10 0.5%, IEC62053-22, class 0.5S, UL Certified, IEC62053-21, IEC62053-22	3 years	NR
3	PMRS/PDP Services Building Energy Use Weather Conditions	Elkor Wattson meter and vendor specific datalogger	ANSI C12	1 year	Broadband and Ethernet
		Vendor specific gateway datalogger	None	Five years for cash customers. Full term for lease customers.	
4	PMRS Services	5% meters per CSI manufactirer list	Meter manufacturer self-certified	5 year + or contract length	Ethernet
5	PMRS Services Building Energy Use	Vendor specific hardware consisting of power meter with datalogging, multiport comms, 1 digital input and 1 digital output	NR	90 days	Modem, ethernet or cellular
		Vendor specific hardware consisting of power meter with datalogging, multiport comms, 4 digital inputs, 4 digital outputs, and 4 analog inputs	NR	90 days	
6	PMRS/PDP Services Building Energy Use Weather Conditions	Vendor specific monitoring package	ANSI C12.20	5 year	Clients dedicated LAN or WiFi, or optional EVDO. Works behind firewall with no remote access required.
7	PMRS Services	Vendor specific monitoring package	UL Certified	Sustainable lease (as long as customer is under management, components are warrantied)	Propietary wireless network for use in solar arrays
8	PMRS/PDP Services Building Energy Use Weather Conditions	Vendor specific performance monitoring system	NR	NR	Any IP based method, e.g. wired Ethernet, cellular, POTS
		Vendor specific internet gateway and datalogger	NR	1 year	
		Vendor specific DC combiner monitoring system	UL 1741	1 year	
		Electro Industries - Shark-100S Energy Meter	ANSI C12.20	Electro Industry provides 4 year warranty	
9	PMRS/PDP Services	Vendor specific monitoring package	TUV type tested	12 months (standard), 60 months (extended)	Cellular & Broadband (GPRS & xDSL)
		Individual monitoring and SCADA systems	NA	NR	

Table 3-2: PMRS/PDP Component Offerings

Vendor	Business Model	Component	Testing and certification requirements	Warranties provided	Comm Networks
10	PMRS/PDP Services Building Energy Use Weather Conditions	Vendor specific package for large commercial customers. Monitors system inputs/outputs (for whole systems and series strings), inverter faults, solar irradiance, ambient temperature, back of module temperature and wind speed.	internal	5 year standard	POPS, Ethernet, Cell Modem, Satellite
		Vendor specific package for small to medium commercial customers. Monitors system inputs/outputs (for whole systems and series strings), inverter faults, solar irradiance, ambient temperature, back of module temperature and wind speed.	internal	5 years standard	
11	PMRS/PDP Services	Inverter with integral 5% meter	UL1741, IEEE1547, IEEE62.41	15-year standard limited warranty	Broadband Internet
		Vendor specific communications gateway	EN 60950, FCC Part 15	1 year limited warranty	
		Vendor specific web-based monitoring, analysis and reporting service.	NA	NA	
		Energy Tracking, LLC's WEM-MX family of meters	EN60950, ANSI C12.20	1 year standard	
12	PMRS/PDP Services Weather Conditions	Power Measurement Square D ION8600	ANSI C12.20	Manufacturers Warranty	Internet Connection
13	PMRS/PDP Services Building Energy Use Weather Conditions	Electro Industries - Shark-100 Energy Meter	ANSI C12.20	Manufacturers Warranty	
		Echelon Server (also used for building automation systems)	NA	Manufacturers Warranty	
		Monitoring hardware from inverter manufacturers	NA	Manufacturers Warranty	
		Weather station	NA	Manufacturers Warranty	
		Gateway	NA	Manufacturers Warranty	

3.4.4.6 Meter Costs

There are several specific meter types utilized by PDPs in the CSI Program Of the model numbers provided, a breakdown of costs were researched with the findings listed in Table 3: Meter Costs. The listing represents general prices for meters only, found through internet searches and through direct contact with the manufacturer. Actual costs will vary based on any interconnection hardware (e.g., panels) necessary for installation.

Table 3-3: Meter Costs

Meter	Price
Schneider Electric ION 6200 meter	\$450 - \$800
Schneider Electric ION8600 meter	\$2,050 - \$4,550
GE kv2c Watthour meter	\$299
Electro Industries - Shark-100S Energy Meter	\$695
Electro Industries - Shark-100 Energy Meter	\$395
Energy Tracking, LLC's WEM-MX family of meters	\$800

There are several other meter products available to PMRS providers, which are included in the CSI list of eligible equipment. A thorough review of these products is included in Section E.

4. Section B – Installation Services

4.1 Objectives

This section reviews installation services currently being implemented for solar projects in California performed through two major functional areas:

- Identification and description of current installation and testing services and service providers
- Written review of meter installers and information providers.

The web-based survey, discussed in Section A, identified aspects of PMRS/PDP systems and meter installation, which helped direct and inform the various installation offerings presented in this section.

4.2 Background and Significance

A PMRS/PDP will either install their system themselves or train qualified contractors to perform the work. The installation/commissioning of metering and communication systems is defined and implemented by the PMRS/PDP or the associated contractor. In some cases, an inverter manufacturer or PV installation contractor is also the PMRS/PDP. This section identifies qualified installation contractors, applicable certifications and credentials, standards followed and methods used during installation. Additionally, a range of installation and commissioning costs is provided.

4.3 Research Design and Methods

As part of the web-based survey, KEMA solicited PMRS/PDP providers for information about installers with whom they work. Matrices of the following parameters were developed:

- Product offerings
- Hardware/software cost
- Installation/commissioning cost
- Annual fee for service
- Other costs
- Required field testing

- Registered retailers
- Required certifications/credentials
- Installation standards.

A comparison between PMRS/PDP manufacturers (including their installers) and utility installation practices was conducted. Additionally, each IOU maintains documentation of their electrical interconnection requirements, which were reviewed for this study.

4.3.1 Identification and Description of Current Installation and Testing Services and Service Providers

Completed through surveys of PMRS/PDP providers and metering equipment installers, we were able to:

- Catalog and identify the type of field testing provided and the installation types offered by provider.
- Catalog the range of installation and commissioning costs for various systems and system types.

4.3.2 Written Review of Meter Installers and Information Providers

- A list of PMRS/PDP providers with whom installation firms partner was obtained. This list includes capabilities, certifications, service offerings, and delineation of other services offered by installation firms such as maintenance, warranty repair, emergency services, etc.

4.3.3 Research Results

An overview of the research results relevant to this section include:

- Cost ranges
- PMRS/PDP provider types
- Installation and verification services.

4.3.3.1 Cost Ranges

Due to variations in service offerings, costs vary dramatically. A full system monitoring PV output, weather conditions, and building consumption can cost approximately $15,000. A simpler system that only measures PV output can cost approximately $3,000.

Cost of service can also vary considerably. Some providers include service for free for customers who purchase their systems; others charge an annual fee.

Several PMRS/PDP providers were unwilling to disclose any cost information for their systems. One provider mentioned the highly competitive nature of their business. Others simply were not comfortable disclosing this information.

4.3.3.2 PMRS/PDP Provider Types

The types of businesses that provide PMRS/PDP service vary considerably, but can be loosely separated into three major categories:

- Provider–includes companies whose main business emphasis is on monitoring systems, which can include monitoring weather conditions, power output within individual series strings, inverter fault conditions, and energy-using equipment within a facility.
- PV Installer–several PV installation companies also provide PMRS/PDP service for the systems they install. They typically will not provide this service for other installation companies and do not provide their systems for resale.
- Inverter Manufacturer–a number of inverter manufacturers also include monitoring capability as part of their service offerings. This capability is accomplished through connection to an inverter's data port for display through a web-based browser or to a local computer. Some inverter manufacturers have also included PMRS/PDP service offerings for systems in which their inverters are installed.

4.3.3.3 Installation and Verification Services

The PMRS/PDP provider will either install systems themselves or have qualified PV installers perform the work. The main qualifications for an install include: work needs to be performed by an installer with California C-10 contractor licensure (mainly for the metering portion of the system and performing the grid interconnection) and installation per the National Electrical Code (NEC). There are no standards in use for the IT portion of the system.

Once systems are installed, warranty and maintenance are typically the responsibility of the PMRS/PDP. Should issues arise, the PMRS/PDP and installer have to determine the responsible party for resolving the issue (whether for installation workmanship, equipment, communication network, etc). Further survey responses pertaining to warranties and maintenance are discussed in Section D.

Basic field testing includes verifying output meter readings against other sources (such as the internal inverter meter or a hand-held multimeter), checking other parameters against calibrated field equipment, verification that components communicate with each other, remote diagnostics, and factory calibration.

4.3.3.4 PMRS/PDP Survey Responses

Survey results relevant to this section are provided in Tables 4-1 and 4-2. The providers are the same as those listed in Section A, but with information (in Tables 4-1) focusing on the services provided and the associated costs. The installation firms utilized by PMRS/PDP providers, along with their qualifications and warranties are provided in Table 4-2.

In some cases, a particular question asked does not apply to a particular component; these are listed as “NA” in the tables. Also, in some cases, a particular question was not answered; these are listed as “NR” (No Response).

Table 4-1: PMRS/PDP Product Offerings

Vendor	Business Model	Product Offering	Hardware / Software Cost	Installation / Commissioning Cost	Annual Fee for Service	Other Costs	Field Testing
1	PMRS/PDP Services Building Energy Use Weather Conditions	Basic PV output monitoring	$5,995	$0	$0	$0	Both on-site and remote diagnostic and calibration procedures. The PV meters are tested with a remote diagnostic program for proper installation and checked against the inverter outputs for a sanity check. Weather stations are checked against calibrated field test equipment (digital thermometer and pyranometer).
		Full monitoring system with PV output, building load monitoring and weather station	$15,000	$0	$0	$0	
		PV output and building load monitoring	$8,995	$0	$0	$0	
2	PMRS Services Building Energy Use	NR	NR	NR	NR	NR	NR
3	PMRS/PDP Services Building Energy Use Weather Conditions	PV system output - All costs are included in total PV system price.	$0	$0	$0	$0	All metering equipment is manufacturer calibrated before installation. In cases where a revenue grade standalone meter is used to measure PV production, the meter measurement is compared to the internal meter of the inverter. The acceptable tolerance is +/- 2%
4	PMRS Services	PV system output	$0	$0	$0	apprx $2500 for 5 years of monitoring services with enhanced reporting features for the cutomer.	NR
5	PMRS Services Building Energy Use	PMRS Hardware consisting of Power Meter with datalogging, multiport comms, 1 digital input and 1 digital output	$7,387	$2,400	$800	$0	NR
		PMRS Hardware consisting of Power Meter with datalogging, multiport comms, 4 digital inputs, 4 digital outputs, and 4 analog inputs	$7,900	$2,400	$800	$0	

Table 4-1: PMRS/PDP Product Offerings

Vendor	Business Model	Product Offering	Hardware / Software Cost	Installation / Commissioning Cost	Annual Fee for Service	Other Costs	Field Testing
6	PMRS/PDP Services Building Energy Use Weather Conditions	One revenue grade meter for inverter and one revenue grade meter for building consumption with weather station. Price listed for up to 200 KW system with real-time 1 minute data sampling rate	$9,340	$0	$1,350	Internet connection.	Digital multi-meter, network testing device, revenue grade OEM test software, local utility company manual meter readings and local revenue grade meter display values for one week period.
		One revenue grade meter or utility company pulse feed for building electric and natural gas consumption. Price listed for up to 300,000 SF with real-time 1 minute data sampling rate.	$2,108	$0	$1,000	Internet connection.	
7	PMRS Services	Performance guarantee	NR	NR	NR	NR	NR
8	PMRS/PDP Services Building Energy Use Weather Conditions	Commercial PV Monitoring Kit - Production side energy meter, Internet Gateway	$3,000	$2,000	$150	Internet Connection	System is pre-configured and calibrated in manufacturing. Onsite verification of power factor required.
		Residential PV Monitoring Kit - Production side energy meter, Internet Gateway	$1,800	$1,500	$75	Internet Connection	
		Add-on Weather Station Standard (4 sensors) - 1 Ambient Temperature Sensor w/ radiation shield - 1 Panel Temperature Sensor - 1 Pyranometer - 1 Wind Speed Sensor - Power Supply, Enclosure and communications interface	$2,600	$1,000	$50	$0	
		Add-on 12 String DC Monitoring Combiner Box - 12 String Combiner Box - Monitoring on String Level	$1,600	$500	$80	$0	
9	PMRS/PDP Services	Site unit for metering, IDR, and GPRS/xDSL communication (VPN)	$2,990	$0	$120	$0	NR

Table 4-1: PMRS/PDP Product Offerings

Vendor	Business Model	Product Offering	Hardware / Software Cost	Installation / Commissioning Cost	Annual Fee for Service	Other Costs	Field Testing
10	PMRS/PDP Services Building Energy Use Weather Conditions	For large commercial customers. Monitors system inputs/outputs (for whole systems and series strings), inverter faults, solar irradiance, ambient temperature, back of module temperature and wind speed.	$12,500	$2,000	$1,000	$0	Commissioning, calibrated voltage meter (calibration based on measurement), standards for testing calibration: industry best practices.
		For small to medium commercial customers. Monitors system inputs/outputs (for whole systems and series strings), inverter faults, solar irradiance, ambient temperature, back of module temperature and wind speed.	$5,200	$500	$1,000	$0	
11	PMRS/PDP Services	Local metering and monitoring	$365	$0	$0	$0	None
		EPBB PMRS service	$0	$0	$2	Annual fee is $2 per module monitored, not a flat $2. Also requires broadband Internet connection.	
		PBI PDP service	$800	$0	$2	$800 is the typical cost of WEM-MX meter. Annual fee is $2 per module monitored, not a flat $2. Also requires broadband Internet connection.	
12	PMRS/PDP Services Weather Conditions	Turnkey metering solution, including onsite labor	$3,000	$2,000	$500	$0	NR
13	PMRS/PDP Services Building Energy Use	System for PBI	NR	NR	NR	NR	Field testing and on-site verification that components "talk to each other"
		Inverter based system	NR	NR	NR	NR	

Table 4-2: Installation Qualifications

Vendor	Registered Retailers	Certifications / Credentials	Installation Standards
1	SPG Solar	Require installers to be at least journeyman level electricians or equivalent skills.	NEC
2	NR	NR	NR
3	Installed by PMRS/PDP only	NR	The NEC and any local electrical codes
4	NR	NR	NR
5	NR	NR	NR
6	NR	Licensed electrician, PMRS/PDP partner certification.	Local, State, Federal codes
7	Pacific Power Management, Cupertino Electric, MBL & Sons, Photon Energy Systems	General contractor's license.	General electrical
8	N/A	Electrical Contractors Licence	NEC/Local rules
9	Still looking for retailers and installers	certified electrical installer	NEC
10	Stellar Energy Solutions, Soltage, Clean Power Systems, Offset Electric	PMRS/PDP training certification	NEC, Installation Manuals
11	Systems can be installed by any qualified installer.	None beyond CSI requirements.	NEC
12	None - PMRS/PDP perform all installs	California C-10 electrical contractor Certified meter technician	NR
13	Have a number of partners	Specific Training C-10 Contractor	NEC for meter only (no standard applies for IT installations)

4.3.3.5 Utility Metering Services and Practices

It is difficult to draw a direct comparison between the PMRS/PDP metering services and those performed by utilities. In general, utilities follow the California Independent System Operator (CAISO) requirements. Each utility may have its own requirements, but must follow the CAISO protocols. A brief summary of these is listed below:

- The building owner is required to provide the electrical service entrance in accordance with the National Electrical Code (NEC) and any local requirements from the Authority Having Jurisdiction (AHJ).
- The service entrance must include a socket per CAISO requirements.
- The utility will have specific requirements such as location, clearances, and disconnect requirements for the service entrance.
- The utility owns and utilizes a revenue meter per CAISO requirements. Each utility has a listing of acceptable billing meters they use, which must meet CAISO requirements for revenue-grade meters. These are usually CAISO-certified by the meter manufacturing facility, and provide evidence of ANSI C12 certification and a calibration certificate for each meter shipped. ANSI C12 testing does not need to be performed by an independent laboratory, but may be performed (in whole or in part) by the meter manufacturer.

The PMRS/PDP providers are not directly bound by CAISO. In contrast, the PMRS/PDP general requirements are as follows:

- Installation of the production metering system must conform to the NEC and AHJ requirements.
- Socket meters are not necessary for PV production meter systems. Some PMRS/PDP providers include meters with current transformer (CT) interfaces.
- Per the CSI program, production metering systems must be easily read and understood by the building/home owner. This may simply be remote or web-based displays.
- The building owner will "*own*" the PV production metering system, as opposed to being owned by the utility. Traditionally, the utility assumes ownership of the billing meter only, but all aspects of the wiring, interface socket, and PV system (including wiring, disconnect devices, over-current protection, and system output metering system) are owned by the homeowner or building owner.
- For PBI systems, the meter must be certified to ANSI C12 accuracy by an independent and qualified third-party, or nationally recognized test lab, and the meter must be

included on the CSI metering list as having a +/- 2 percent accuracy. Per the CSI Handbook, evidence of meter accuracy is not required to be furnished for PBI system output meters, but may be requested by program administrators. Evidence of meter certification can be met by a test report, certificate of compliance, or a calibration and final-test report. Meters for EPBB systems can be manufacturer self-certified to +/- 5 percent accuracy.

5. Section C – Data Transfer

5.1 Objectives

The objective of this section is to review and analyze the potential data flows, formats, and transfer points from the meter through the data collection process, delivery to the meter data repository, and to the CSI Program Administrators for CSI PBI for reporting and payment purposes. This same information will be reviewed looking at requirements to certify renewable energy credits (RECs) for the Western Renewable Energy Generation Information System (WREGIS).

The specific data transfer research objectives were to identify the possible data flows based on current available processes and procedures as well as recommended future infrastructures. The results of this research are illustrated separately for both the EPBB and PBI to highlight the different requirements of each.

In addition, a comparison between the potential system implementations and formats is made, based on measurable characteristics including service levels and cost, both of which affect total cost of ownership and operations.

5.2 CSI Data Requirements

This report's focus is on the regular (computerized) data requirements that apply to regular data transfers. The requirements for forms that are interchanged to apply for a CSI installation will not be discussed. The EPBB program systems that do not meet the cost cap are not being taken into account, since there are no data requirements regarding solar-generated energy for this program. However, systems qualifying for EPBB are required to have a meter to verify electrical energy generation. Using EPBB, a calculated energy generation estimate is used to decide how much of the investment is '*subsidized*' by the program; because of the cost cap, very few EPBB systems are actually monitored. [2]

[2] Since the CSI database architecture originally has not been set up to track the exact number of exemptions, no actual numbers of the segregation are known.

5.2.1 Requirements for Maintenance and Incentive Payment

EPBB

The owner must provide an electric meter with +/- 5 percent accuracy measuring the output of the solar system. The data collected and provided by the PMRS is used to monitor the performance and report production to the system owner. There are currently no format requirements for reporting in place. Acquiring and processing the data has to be done by the PMRS on a daily basis, and a frequent mandatory report (e.g., once per month) from the PMRS is due to the system owner. Additionally, system owners must have on-demand access to the processed data.

Program administrators must be provided with 15-minute interval data on request for a minimum of two years from the actual production date.

PBI

For systems under the PBI, a monthly data report is required that includes 15-minute energy generation data and is referred to as a "*Performance Report*."

The data has to be acquired and processed on a daily basis. The performance report is produced on a monthly basis and can be sent using an excel-file, but electronic data interchange (EDI) 867 is preferred and will become mandatory starting May 2009. (EDI 867 is described in Appendix D.)

5.2.2 Requirements for WREGIS/ RECs

5.2.2.1 Background

Renewable energy credits (RECs) are tradable environmental commodities, which are proof that 1 megawatt hour (MWh) of electricity has been generated from renewable sources. The energy associated with a REC can be sold, combined with the REC, or sold and used separately by another party.

The REC market in California is a compliance market created by the Renewable Portfolio Standard (RPS) program, which requires utilities to supply 20 percent of their electricity from renewable generators by 2010. This can be achieved by either building renewable facilities, such as wind farms, solar farms, biomass plant, etc., or by buying unbundled RECs from renewable energy generator owners.

In California, there is a distinction between unbundled RECs and tradable RECs (TRECs). Unbundled RECs can be sold to a load serving entity (LSE), but cannot be resold after being sold. Tradable RECs can be sold to a LSE and resold after that. This distinction will not be elaborated on, since the significant distinction in this research will be on whether a REC can be sold independently of the generated renewable energy or not. This will provide a geographic flexibility for renewable energy generated within the State of California.

In Figures 5-1 and 5-2, a simple example illustrates the use of unbundled RECs. In the first figure, both utilities (A and B) meet their load obligations of 100 MWh from conventional facilities. In the second figure, Utility B meets its load obligation by generating 90 MWh from conventional facilities and also contracts 10 MWh through a renewable facility. However, the corresponding RECs are not bought by Utility B; they are bought by Utility A. Utility A receives the benefits associated with the renewable attributes, but does not receive the actual energy. Utility A therefore claims a 10 percent renewable-source generated energy load, whereas utility B cannot claim any renewable source energy load.

Figure 5-1: Two utilities servicing their demand load using conventional facilities.

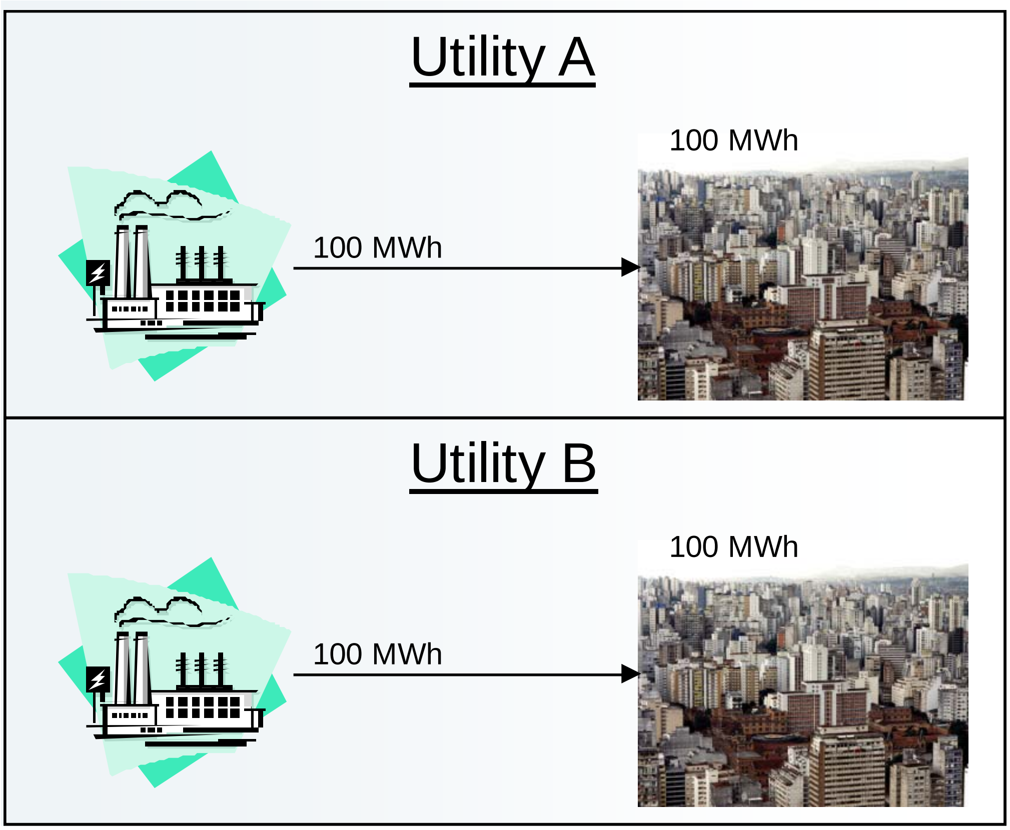
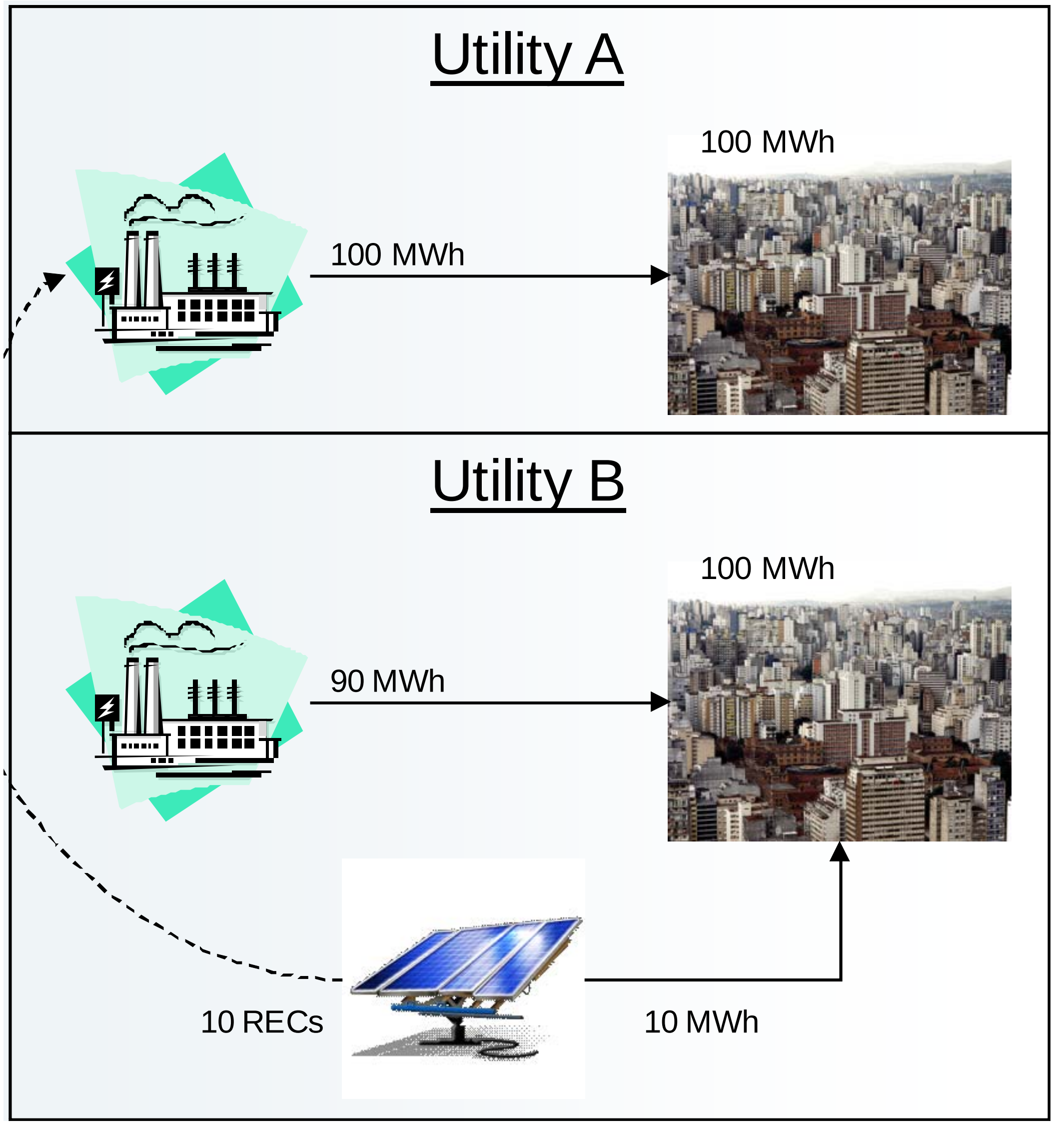


Figure 5-2: RECs are sold separately from the associated energy.



The current prices of RECs fluctuate heavily, but range between \$0.005/kwh and \$0.056/kwh,[3] translating to \$5 to \$56 per MWh. Sales of RECs represent additional income for the solar system owners.

[3] http://apps3.eere.energy.gov/greenpower/markets/certificates.shtml?page=1

5.2.2.2 General REC Requirements

Under current legislation, solar systems (PV) under the CSI are not eligible for use under the California RPS program. There seems to be no monetary incentive to register the generated solar energy within WREGIS. However, current developments in legislation indicate a desire to include CSI-generated solar energy in the RPS program (see the proposed authorization of TRECs towards RPS, which is required to certify distributed generation facilities for RPS eligibility by the CEC).

As stated earlier, one REC is defined as a certificate proving that 1 MWh of electricity has been generated from one or more renewable sources. To qualify for a REC, WREGIS has several classes of generation facilities, which are discussed in the next section. For the decentralized generation classes, the metering requirements are: ANSI C12 standard and metered at the AC output of the inverter.[4] If there is no meter at the facility's physical location, positive generation flowing to the distribution system (grid) should be measured hourly to qualify for the creation of certificates at WREGIS. These RECs are awarded only for electricity generated in excess of the facility's demand load. If there is a meter at the inverter output, RECs are awarded for all electricity generated by the distributed generation (DG) (solar) facility. However, certificates will not be issued for solar-generated electricity that is used to supply the generation unit itself; the meter should be placed after that point to measure net power generated.

5.2.2.3 Tracking RECs

The WREGIS tracks RECs, which consist of both renewable energy generation and trading tracking—both for unbundled and tradable RECs.

The WREGIS recognizes 10 classifications of generating units. All solar systems are assumed to be "customer-sited distributed generation," and, therefore, part of Class H–J. We have provided an overview of classes H-J in Table 5-1 and a comprehensive table in Appendix E listing all WREGIS classes.

[4] Per CSI requirements a meter has to be installed at this point.

Table 5-1: WREGIS Generating Units Classifications

Class	Determinant
H	Nameplate capacity greater than 360 kW.
I	Nameplate capacity less than or equal to 360 kW and with an annual production technically capable of exceeding 30 MWh per year.
J	Nameplate capacity less than or equal to 360 kW and with an annual production technically not capable of exceeding 30 MWh per year.

Class H Data Reporting

Data files are to be electronically transmitted to WREGIS by a qualified reporting entity,[5] according to specified data format.

Class I and J Data Reporting

There are two reporting options:

1. Data files can be electronically transmitted by a qualified reporting entity, according to specified data format.
2. Data can be submitted using the self-reporting interface, under which the generator owner can submit cumulative meter reads (MWh or KWh) on a monthly basis.

Note: *A source smaller than 1 kW cannot be registered with the current WREGIS software as a stand-alone unit.*

5.2.3 Foreseen (Potential) Requirements

Low Penetration of Solar Generation

No additional requirements for CSI.

[5] In the WREGIS operating rules the title "Qualified Reporting Unit" is not limited to a set number of entities. Qualified Reporting Entities may include balancing authorities, the interconnecting utility, schedule coordinator, independent third-party meter reader, Generator Owner, or Generator Agent, as the Qualified Reporting Entity has a signed agreement with the WREGIS administrator.

Medium Penetration of Solar Generation

There are additional data requirements for EPBB, so all generation is visible and foreseen and can be used for REC acquisition.

High penetration of Solar Generation

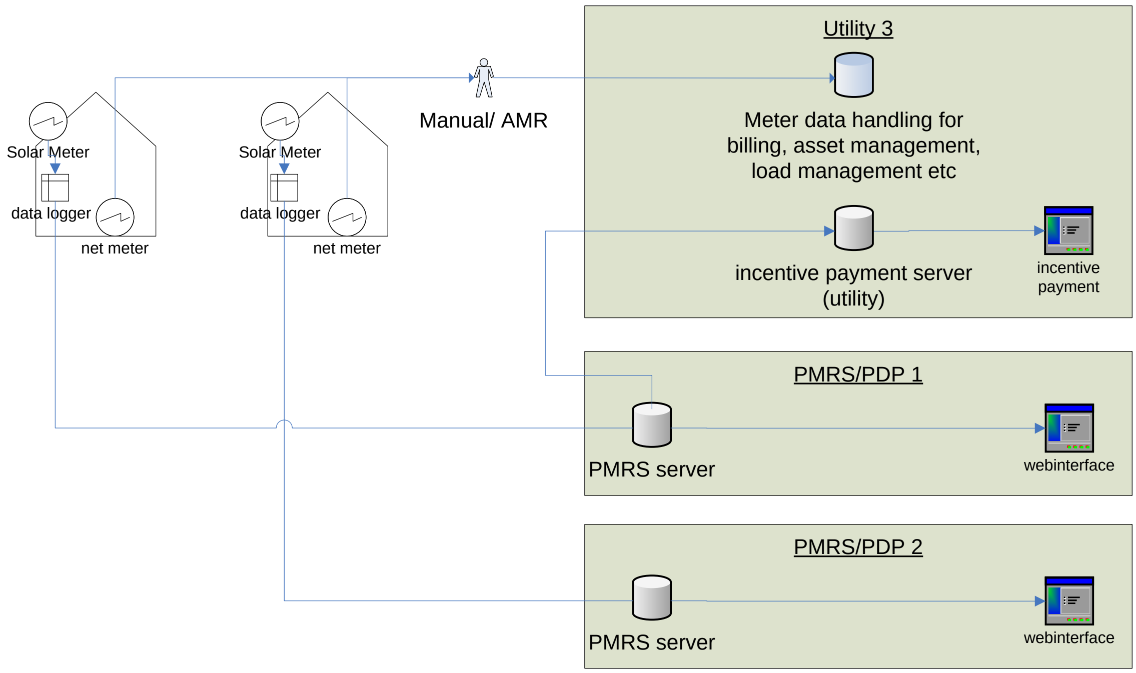
Near real-time (e.g., with a 24-hour delay) generation data is required, so load generation can be forecasted and conventional, centralized generation can be properly planned. Distribution is the second process where accurate solar generation data is useful with a high penetration of solar. As distributed generation increases, the distribution network is used in a manner that differs from the original use of the distribution network. Insight on power transported within the distribution network is necessary for appropriate distribution planning, especially for solar-generated energy which is very inconsistent and dependent on weather conditions. Proper forecasting relies on detailed generation (and grid feeding) data. Furthermore, maintenance/safety issues may arise with high solar generation penetration. The possibility of DG facilities' disconnects have to be evaluated to avoid feeding into the grid.

In conclusion, as the penetration of solar generation grows, even for EPBB, a regular generation report would be useful for a utilities' consideration. An additional business case preparation should be considered, since current monitoring comes at a relatively high cost, hence the cost cap. Using AMI-ready meters—either as separate AMI meters or as HAN meters—could give a utility timely and accurate generation data to forecast load generation and plan distribution.

5.3 Current Data Transfer and Metering Technologies

Figure 5-3 demonstrates the process for measuring and monitoring solar output.

Figure 5-3: Current data transfer process.



As depicted, the solar meter registers actual generated energy, which is stored in a datalogger—either integrated with the meter or separate. Using internet technology, the data is read by the PMRS, sent to a PDP[6], and from the PDP is sent to the Program Administrator. If there is no PDP (this is the case for all EPBB installations), these last two steps will not occur. The PMRS uses the data for system monitoring and to present solar-generated power outputs using a web interface to the system owner.

Should there be any excess power generation (not used by the facility/owner), the power will feed into the grid and be registered as 'credit' through the bi-directional utility net meter. This data can be collected using meter readers, automatic meter reading (AMR) or advanced metering infrastructure (AMI) (the first one is shown in Figure 5-3), and is used mainly for the utility billing process.

The following processes in Table 5-2 are in place to capture solar data.

[6].All PDPs must be PMRS providers first, so this is shown as an integrated activity.

Table 5-2: Techniques/ Interface Used for Solar Data

From	To	Technique	Remarks
Solar output meter	Datalogger	n/a	15-minute, 5-minute, and even minute interval logging is available in the market. The meter is read at various intervals from 3-6 seconds to 15 minutes.
Datalogger	PMRS	Internet	Every PMRS can choose its own technology to acquire the desired data. Also, the PMRS can acquire and choose its data, as long as generated energy (in kW and kWh) with a 15-minute interval is registered and stored. The data has to be retained for 60 days, with a monthly reporting schedule, and 7 days, with a daily reporting schedule.
PMRS	PDP	n/a	There is no specific data format requirement or collection technique used. This is a matter between the PMRS and the PDP. (Since PDPs have to be PMRS providers first, these are the same entities.)
PDP	Program Administrator	EDI/ XLS using (S)FTP, email	At the moment, XLS files are sent. Starting May 6, 2009; communication by EDI 867 is mandatory.

Data transfer protocol of EDI 867

Defined in the CSI Handbook Appendix H, CSI has mandated that all data transfer is made in a specific format and is provided using EDI 867 to program administrators from PDPs. SCE is collects data from various PMRSs in their own servers. PG&E and the CCSE are outsourcing the data collection through EDI. See CSI Handbook Appendix A, Section F for more information.

5.4 Current Data Process Flows

Current data process flows can be roughly divided into three categories:

- Data process flows for PBI
- Data process flows for EPBB not exceeding metering and communication cap
- Data process flows for EPBB exceeding metering and communication cap.

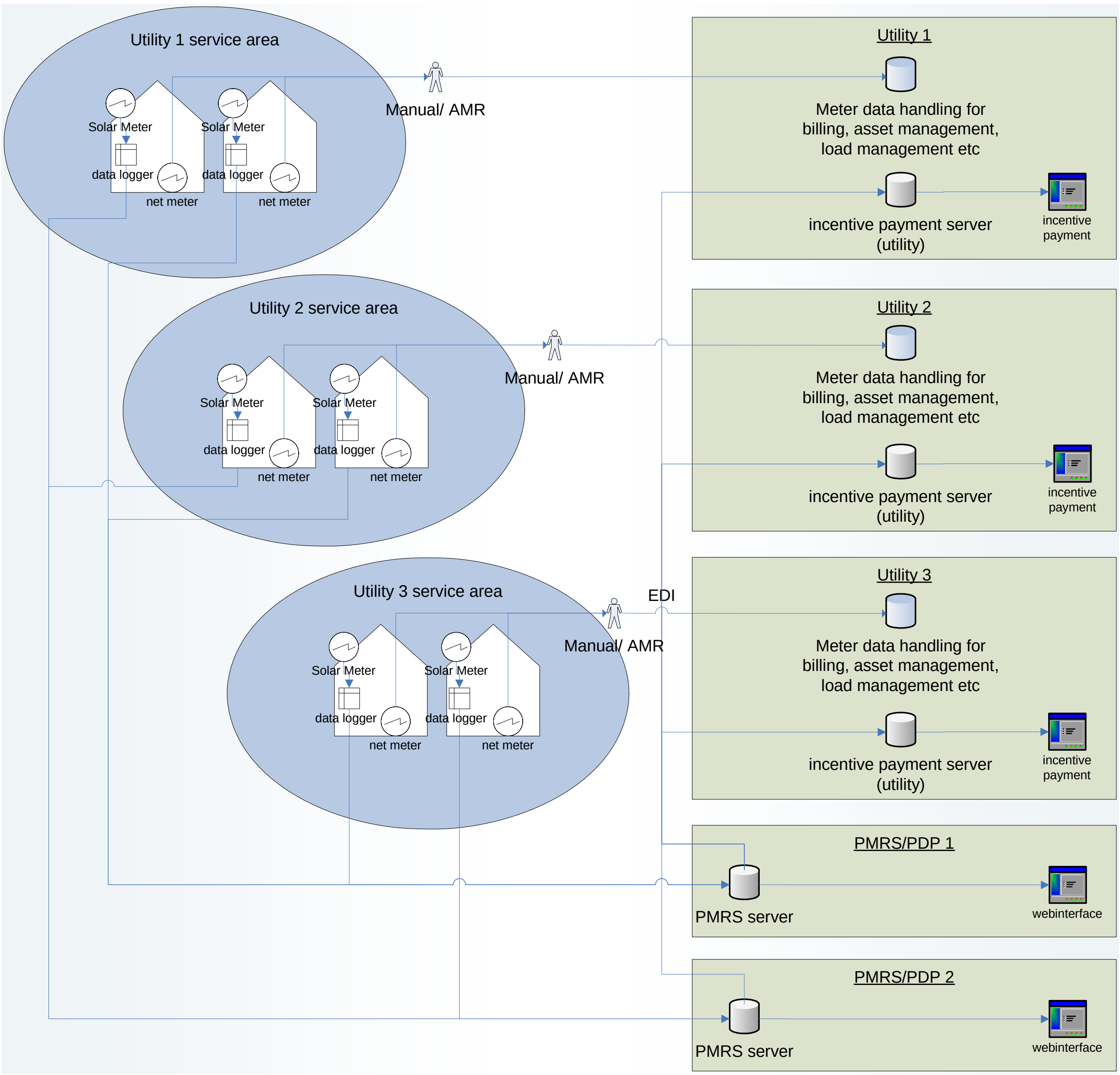
For the latter, there is no data process flow required. The other two will be addressed in the following sections.

5.4.1 Current Data Process Flows for PBI

As depicted in Figure 5-4, generated energy readings are registered by the solar meter and stored by the datalogger. The datalogger has to retain collected data in the event of a power outage and be able either to retain the data for 60 days or for 7 days: 60 days for all onsite reporting dataloggers and remote reporting dataloggers with a standard monthly reporting schedule; and 7 days for remote reporting dataloggers with a standard daily reporting schedule. In all cases, either the meter or the datalogger has to retain lifetime production. The datalogger is connected to the internet using a gateway, and stored data is accessible for the PMRS or is sent to the PMRS on a regular basis. The PMRS analyses the data to determine solar installation performance and acts on disturbances. The data is accessible for the system owner to view system performance, using graphs, historical data, etc. The data is also accessible by the program administrator (from the utility), either by sending the data or making it accessible for a PDP who sends a monthly performance report to the utility.

The data logger registers and stores electrical energy generation output. Generally, the internet transfers the data from the datalogger to the PMRS server via a local area network (LAN), Ethernet (10 baseT-RJ45, TCP/IP, HTTP, FTP, XML), cellular, or dial-up modem.

Figure 5-4: Data Process Flows for PBI.



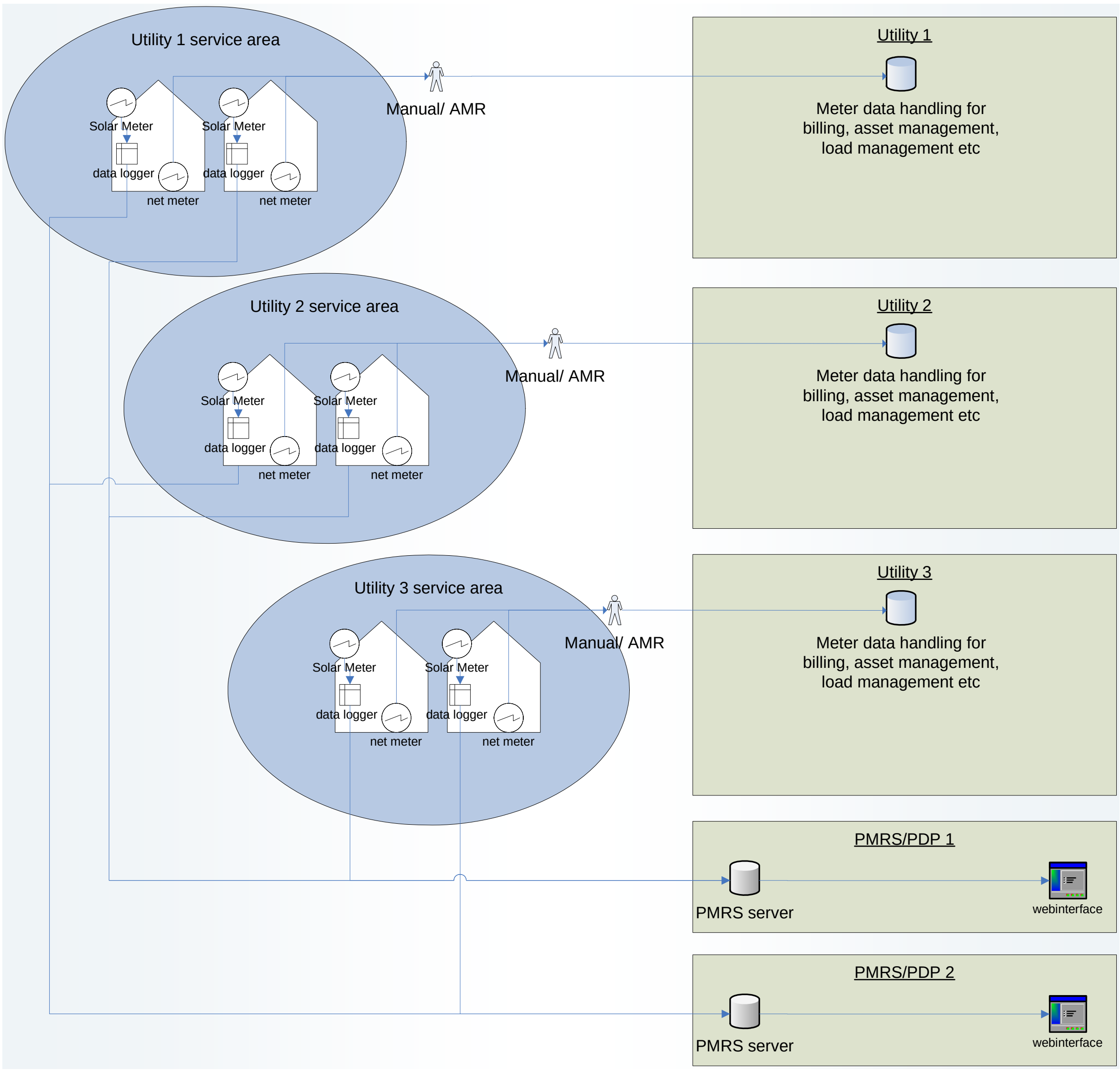
For transfers from the PMRS (PDP) to the program administrator, the following options are used:

- Excel files are sent using email
- EDI 867 messages are sent over a secure File Transfer Protocol (FTP) connection.

5.4.2 Current Data Process Flows for EPBB not exceeding Metering and Communication Cap

As illustrated in Figure 5-5, generated energy readings are registered by the solar meter and stored by the datalogger. The data retention requirements are the same as for PBI. The datalogger is connected to the internet using a gateway, and the stored data is accessible for the PMRS or is sent to the PMRS on a regular basis. The PMRS analyzes the data to determine solar installation performance and provides alarms for performance. The data is accessible for the system owner to view system performance, using graphs, historical data, etc. The data is also accessible for the PA through the PMRS who sends the data at the request of the PA.

Figure 5-5: Data Process Flows for EPBB with Monitoring.



5.4.3 Current Data Process Flows for EPBB exceeding Metering and Communication Cap

There is no requirement for data flow for this category.

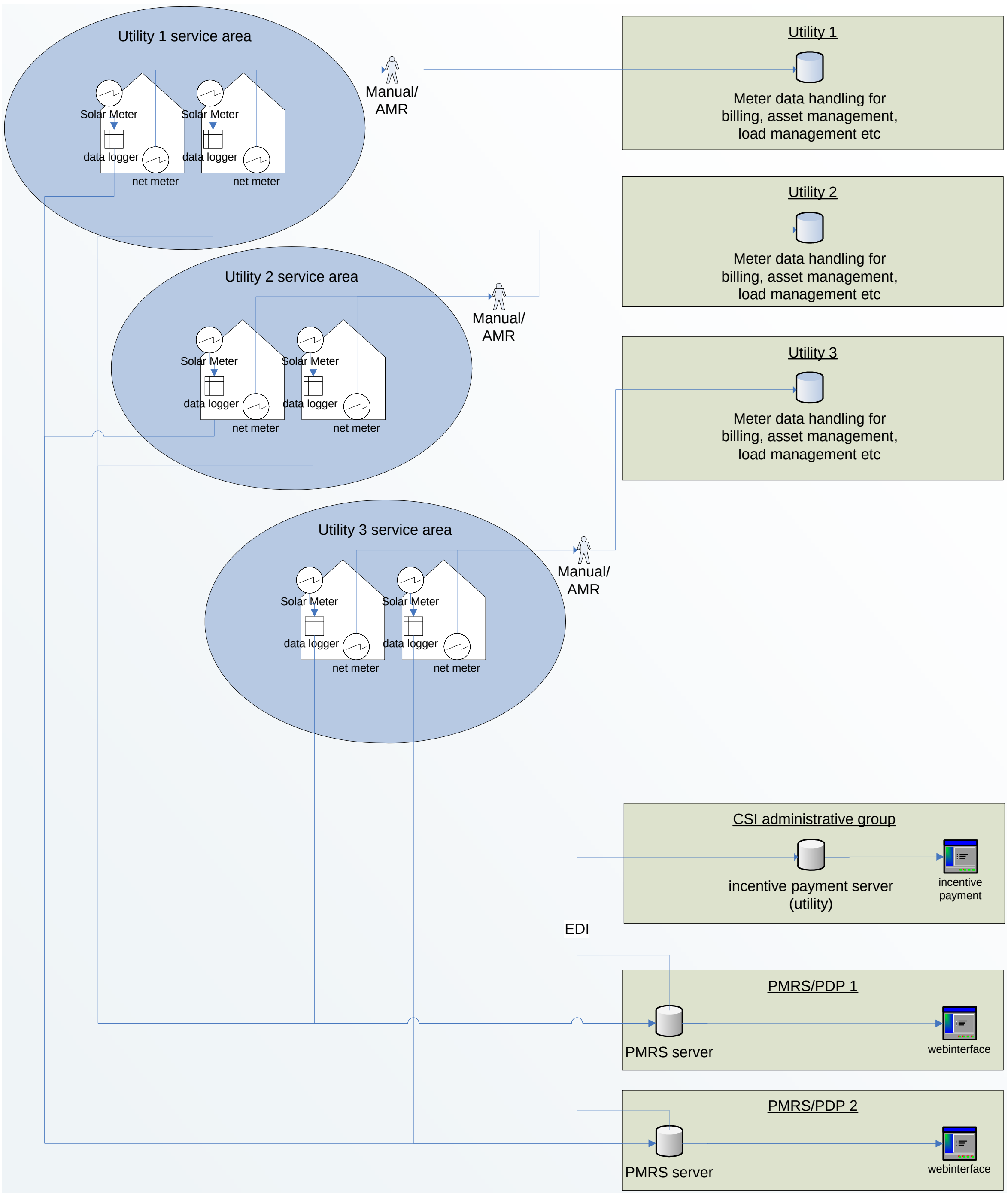
5.5 Potential Data Process Flows

5.5.1 Potential Data Process Flows for Performance Management and Incentive Payments

Integrating the incentive payment process through one entity would make CSI qualification and data transfer processes easier, since the PMRS/PDPs would not have to perform duplicative functions— three different entries, three different addresses, etc.

This option assumes the incentive payment is not integrated within the utilities, as shown in Figure 5-6.

Figure 5-6: Potential Data Process Flows Performance Management and Incentive Payment.



5.5.2 Potential Data Process Flows RECs/ WREGIS

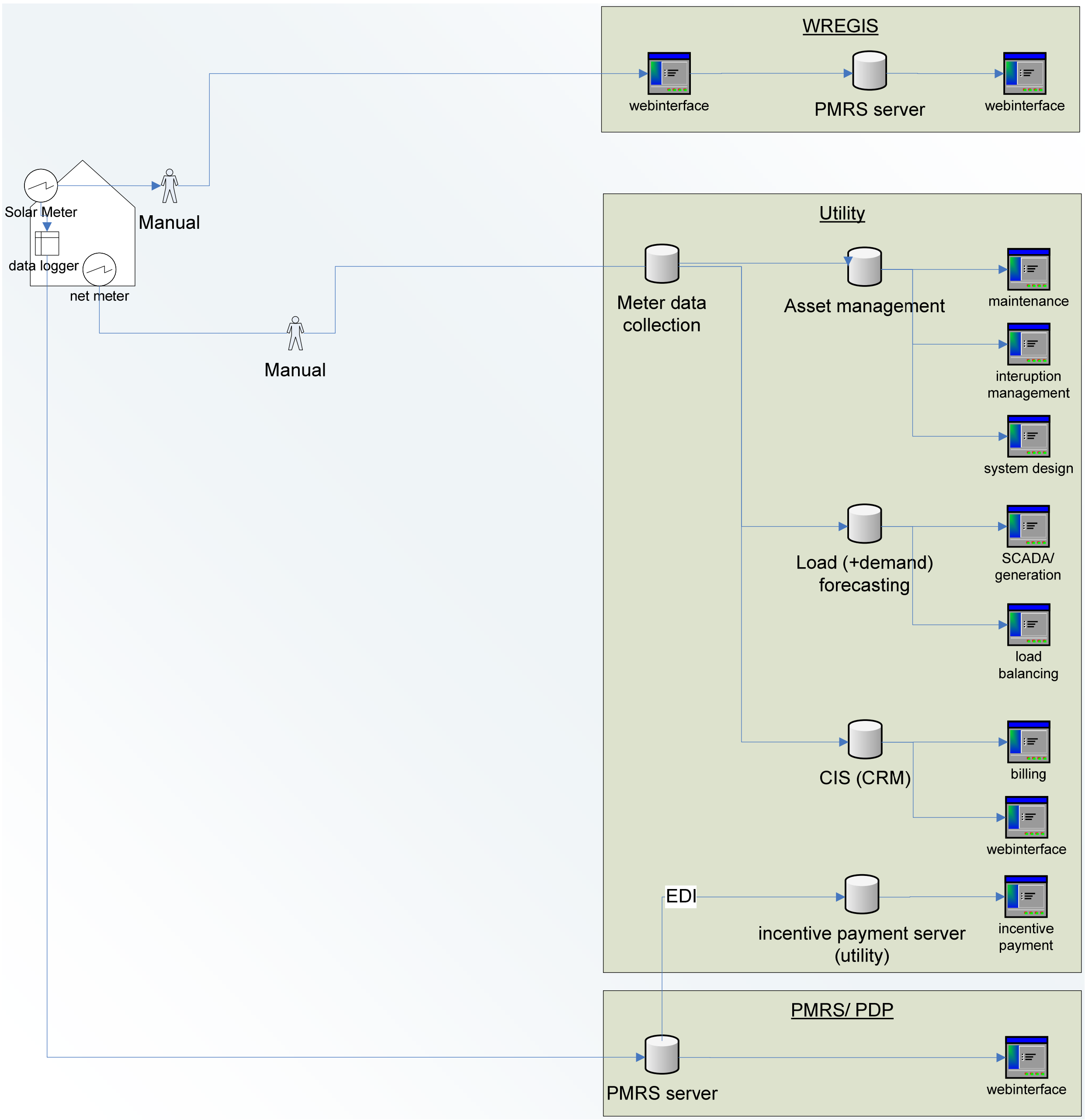
Since CSI solar systems do not currently qualify for the RPS compliancy, some possible data flows have been drawn to show possible future flows. At the moment, there is no incentive to register the RECs with the WREGIS.

5.5.2.1 Option 1

As shown in Figure 5-7, solar system owners will enter the cumulative meter reads from a compliant meter into the WREGIS system to gain RECs. RECs are then awarded separately from all other process flows.

The PMRS/PDP still monitors performance (and commences maintenance based on the performance) and submits meter data to the utilities for incentive payments.

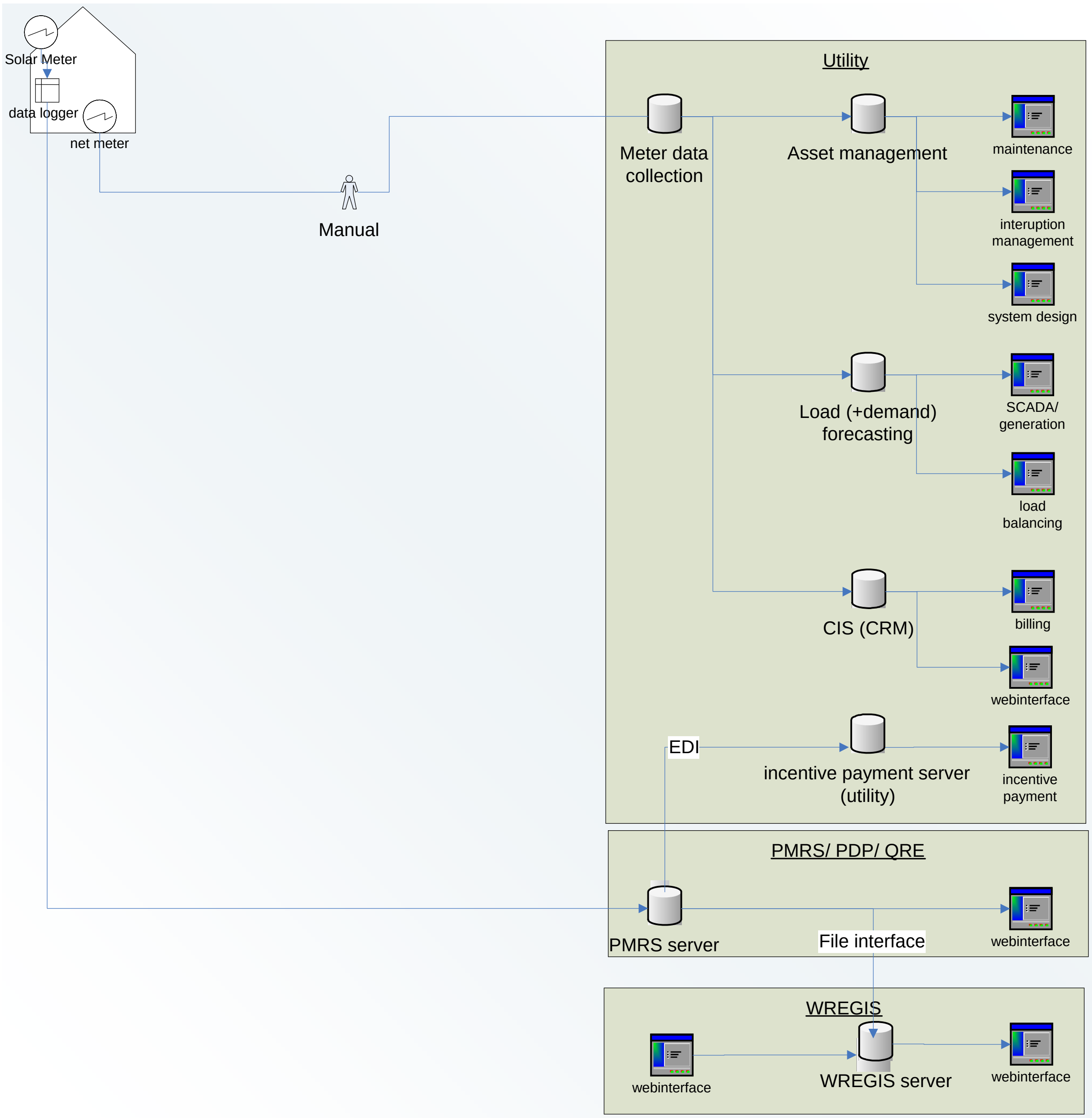
Figure 5-7: Data Process Flows RECs/ WREGIS, Option 1.



5.5.2.2 Option 2

As shown in Figure 5-8, entering manual meter reading data does not occur, but the PMRS/PDP uses the WREGIS file transfer system to enter solar energy data generated by the applicable solar system. The PMRS/PDP acts as a qualified reporting entity. The data will also be used to monitor the system—still a PMRS function— and the PMRS sends generated energy information to the utility for incentive payments (PBI only).

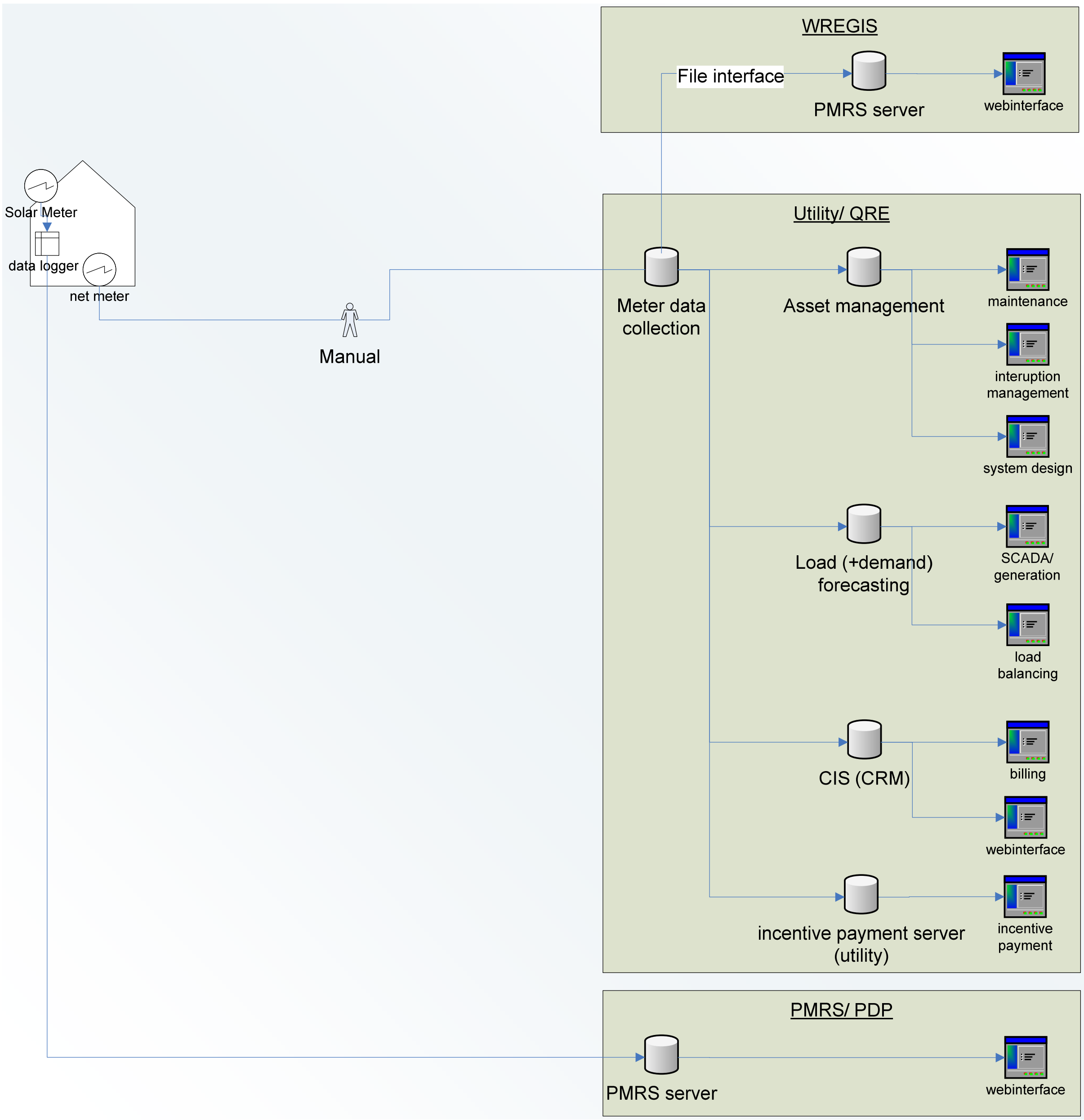
Figure 5-8: Data Process Flows RECs/ WREGIS, Option 2.



5.5.2.3 Option 3

As shown in Figure 5-9, generated energy data is collected by the PMRS for performance and maintenance purposes only (note that there is no PDP). The data is also collected by the utility, both for billing purposes (including incentive payments, asset management, load management etc.), and transferring the data to the WREGIS to acquire RECs for the generated energy.

Figure 5-9: Data Process Flows RECs/ WREGIS, Option 3.



5.6 Cost of Data

5.6.1 Cost of Data Transfer Protocols

There is currently no legislation that mandates specific communication processes or technologies, so there is considerable latitude and flexibility in this area. In general, current conditions mirror the following costs for frequently used technologies:

- Cellular: $0.50/day, since there has to be daily reporting + a monthly fee
- Internet: PMRS providers can require an existing internet connection. There is no additional cost.
- Dial-up: same as cellular
- AMI integration: 0.

Since the data to be transmitted is rather small (approximately 2x 196 values + header + footer), few efficiency gains will be realized by using different data transfer protocols.

5.6.2 Recommendations

Efficient data transfer mechanisms enable many types of markets around the globe. From a technical perspective, data transfer is simply moving data from one system to another; but from a business perspective, it allows many different systems designed for different purposes to work together. Data transfers allow systems to remain synchronized, reduce the duplication of data, and enable disparate systems to cooperate towards common business goals. Thus, well-defined data transfer mechanisms and protocols are a key element for success.

Many markets have used common standards for meter and meter data communication to enable deregulation and competition. One of the items that should be given attention is the use of communication protocol standards from the solar system to all other parts of the communication chain. This would allow system owners to get another PMRS/PDP if the current PMRS/PDP cannot continue its business, and it gives the system owner options in case the expected service levels are not met by its current PMRS/PDP. Besides these client benefits, it will also allow utilities to integrate the system for incentive payments, REC registration, and possibly AMI integration. For example, interoperability is a major issue in Europe (especially the Netherlands) for utility communications, which is done to avoid dependency on one meter supplier.

Furthermore, since billing frequency, units, line items, etc. may vary between AMI and PV, data transfer becomes an integration point that must reconcile these differences.

If data transfer across California is only required for incentive payments, then a centralized integrated process needs to be utilized across all utilities to provide administration uniformity and reduction of data collection cost. For example, the:

1. Application approval process should be uniformly administered across California
2. Program administration cost (e.g., PMRS filing data for program effectiveness) should be reduced by monitoring all solar installations, especially anticipating potential REC market needs.

The authors strongly recommended that CSI program administrators collect residential solar monitoring (EPBB) results to analyze EPBB installation data, and adjust the generation forecast as necessary, and be able to evaluate the whole CSI program. Currently, there are no required standards for this data in the CSI Handbook; standards for this data transfer should be developed. Using the same standards that are in effect for the performance report might be an easy solution, but possibly using different time intervals. Important considerations for these requirements include:

- Having no, or limited, costs for rate payers, PMRSs, and solar owners
- Using standards that qualify for RECs acquisition to improve return on investment and/or lower costs for the owners.

Residential and commercial solar monitoring (EPBB) could be provided through the AMI by utilities, where cost from PMRS is prohibitive. Furthermore, program administrators should keep track of the number and expected performance for these installations. It is recommended that program administrators request generated energy, meter read by the owner, for verification purposes. The authors suggest performing this verification process once a year, which would lower both program administrators' and installation owners' efforts.

The information acquired can be used for both fine-tuning the calculation method and the effectiveness of the CSI program.

For larger installations (PBI), a plan needs to be developed that addresses receipt and/or storage of data five or more years old.

As soon as the CSI qualifies fully for the WREGIS RECs Program, the following issues should be considered:

1. Depending on the number of small (< 1 kW) installations, program administrators should consider aggregating the generation of these installations, which would allow the owners of smaller (solar) generating units to contribute to RECs. To accomplish this, generating information from these units would be required regularly, at least monthly, through a mandatory monthly owner read (entered on the website), through a PMRS, or through an AMI-compatible meter read by the utility.

2. The PMRS/PDP should report generated energy for solar energy installations. This would increase the added value of the PMRS/ PDP and be used more often by solar generation unit owners.

Combining reporting functions, whether through PMRS/ PDP or the utilities, will increase value for these entities and their total savings. Specific differences between CSI and WREGIS requirements should be studied separately.

6. Section D – Performance Monitoring and Reporting Service Providers

6.1 Objectives

In this section, we review the functionality and business offerings of the various PMRS providers. .As discussed in Section A, a web-based survey directed and informed our research for this report. Within this section, we have provided simple block diagrams of several PMRS systems and a matrix of various business offerings.

6.2 Background and Significance

At the time of this study, 37 PMRS providers were approved as eligible under the CSI. When the CSI started, there were only three providers who had developed metering/data transfer systems targeted for renewable energy customers. Some of the newer PMRS providers have historically been general information service providers that have expanded to the renewable energy market.

6.3 Research Design and Methods

Of the 37 PMRS/PDP providers invited to participate in the survey, 13 providers responded. They were asked specific questions surrounding:

- Business practices
- Services offered
- How data was recorded
- Software/firmware upgrade procedures
- Warranty offerings
- Service guarantees.

Simple block diagrams depicting systems they offered were obtained through either direct submittal by the PMRS/PDP or through internet searches.

Our examination of three key PMRS/PDP provider areas looked at:

- Identification, description and evaluation of existing product, and service offerings

- Product and service offerings were obtained and system differences evaluated.
- Identification, description and evaluation of long-term maintenance offerings
  - Required maintenance and available warranties were obtained from the PMRS providers.
- PMRS business evaluation
  - Business practices were obtained.

6.4 Research Results

An overview of the research results relevant to this section include:

- Service offerings
- Business practices
- Maintenance and warranties.

6.4.1 Service Offerings

The minimum required PMRS service requires measuring and recording instantaneous AC kW and net kWh generated by the PV system. Data recording must be performed in 15-minute intervals (minimum), and PDP providers must communicate this data to the PA. Survey respondents provided information demonstrating that many PMRS/PDP providers offer services beyond reading and recording system energy output, including:

- Weather monitoring
  - Ambient temperature
  - Wind speed
  - Back of module temperature
  - Solar irradiance
- DC output of each PV series string
- Failure signals from the inverter
- Building energy use
- Training and support
- Performance benchmarking and data evaluation
- Customer web site interface
- Public information displays
- Planning integration curriculum for educational institutions.

Such information is vital in detecting whether the system is performing to its maximum potential. Providers utilize these additional data points to either send a service technician out to a site or to alert the customer about necessary maintenance.

6.4.2 Business Practices

There are a wide range of business practices among PMRS/PDP providers. Some key elements of the various business practices include:

- One PMRS/PDP obtains needed equipment from inverter and/or meter manufacturers and self-installs the system.
- One PMRS/PDP also provides energy consulting services, including assistance on energy use optimization. Provider monitors and trends energy use, power quality, and cost of energy to provide guidance on optimizing energy use.
- One provider stated that they have no formal business partnerships with manufacturers or contractors.
- Typical PMRS/PDP alliances include partnerships with PV system installers and distributors and with general and electrical contractors. Further information on specific contractors the PMRS/PDP providers partner with is included in Section B.

6.4.3 Maintenance and Warranties

Each PMRS/PDP surveyed will upgrade software remotely, typically at no charge. Some can upgrade firmware remotely, and some will upgrade during service calls. One provider stated firmware updates, if required, must be performed as a time and material work order. Other providers will update firmware free of charge or along with other service they are performing.

Of the eight respondents offering warranties, most offer a minimum five-year warranty with two respondents providing only a year for the monitoring systems. Beyond that, warranties varied by system type and manufacturer warranties.

Five providers offered responses about service guarantees with one vendor indicating the topic was not applicable and another noting that no guarantees were offered. Of the three remaining responses, service guarantees varied greatly with no consistent offerings.

6.4.4 PMRS/PDP Survey Responses

Results of the survey pertinent to this section are included in Tables 6-1 and 6-2. These are the same providers listed in Section A, but information focuses on business practices, maintenance, and warranty offerings.

In some cases, a particular question asked does not apply to a particular component; these are listed as “NA” in the tables. Also, in some cases, a particular question was not answered; these are listed as “NR” (No Response).

Table 6-1: Business Practices and Services Offered

Vendor	Business Practices	Services Offered	Data Recorded
1	NR	NR	Both instantaneous and cumulative data as well as weather information. Too numerous to list here.
2	NR	NR	NR
3	PMRS/PDP self-installs all products. Works with inverter and meter manufacturers to provide needed equipment.	Provides performance evaluation, benchmarking, energy consumption monitoring, system alerting, and error reporting. Weather and irradiance monitoring is provided when required by installing third-party monitoring systems.	Collects cumulative kWh, voltage, and current. Other parameters are collected as needed.
4	NR	NR	NR
5	Technology solutions to manage energy usage for utility, industrial, campus and commercial power systems. Provides services for energy metering & cost allocation, power quality & advanced monitoring systems, and consulting on energy system optimization. Experienced with metering systems from: Cutler Hammer, Dranetz-BMI, EMON, Electro Industrial, Flexcore, GE, Power Measurement Ion, Schneider Electric/ Square D, Siemens, Trafox	Provides metering hardware and design, electrical installation, software installation & configuration, business critical reports, IT communications configuration, ongoing maintenance, training and support	NR
6	NR	NR	Data every minute including kwh, kw, amps, volts, PF, solar radiance, panel temp, wind speed, outdoor air temp, solar array generation, building energy consumption, net in, imported & exported, greenhouse gas, heating & cooling degree day, weather consition description, system performance indicator
7	NR	NR	NR

Table 6-1: Business Practices and Services Offered

Vendor	Business Practices	Services Offered	Data Recorded
8	NR	Provides performance data evaluation, performance benchmarking, customer energy consumption monitoring, weather and irradiance monitoring, system alerting, error reporting	kwh exported/imported, instantaneous power, demand, DC string current, inverter status, irradiance, temperature, windspeed, wind direction,
9	NR	NR	NR
10	Partially owned by another company	Performance data evaluation, performance benchmarking, customer energy consumption monitoring, weather and irradiance monitoring, system alerting, error reporting, public information displays, customer website tie-in, planning integrated curriculum for educational institutions	Monthly kWh, peak kW, interval data, solar irradiance, wind speed, wind direction, back of module temperature, horizonal irradiance, POA irridiance, ambient temperature, AC voltage and current measurements, THD, DC current and voltage measurements per string, inverter status, inverter fault conditions, tracker status and faults. All at 15 minute intervals.
11	Sells product line via a distribution channel as well as through select direct customers. Various business alliances with solar industry vendors, which include development alliances, distribution/sales alliances, and marketing alliances. Recommends the Energy Tracking meter as part of its standard PMRS solution.	Includes email alerting functionality and error reporting.	For EPBB: 5-minute interval data (Wh, temperature) - inverter based meter For PBI, in addition to the above: 5-minute interval data (Wh, peak kW) and cumulative kWh - separate output meter
12	We have no formal business partnerships with manufacturers or contractors.	Weather and irradiance monitoring, System alerting based on No Data conditions or outlying data conditions.	Monthly kWh, Interval kWh, Interval Avg kW, Irradiance, Wind Speed/Direction, Cell Temp, Ambient Temp
13	NR	NR	NR

Table 6-2: Maintenance and Warranty Offerings

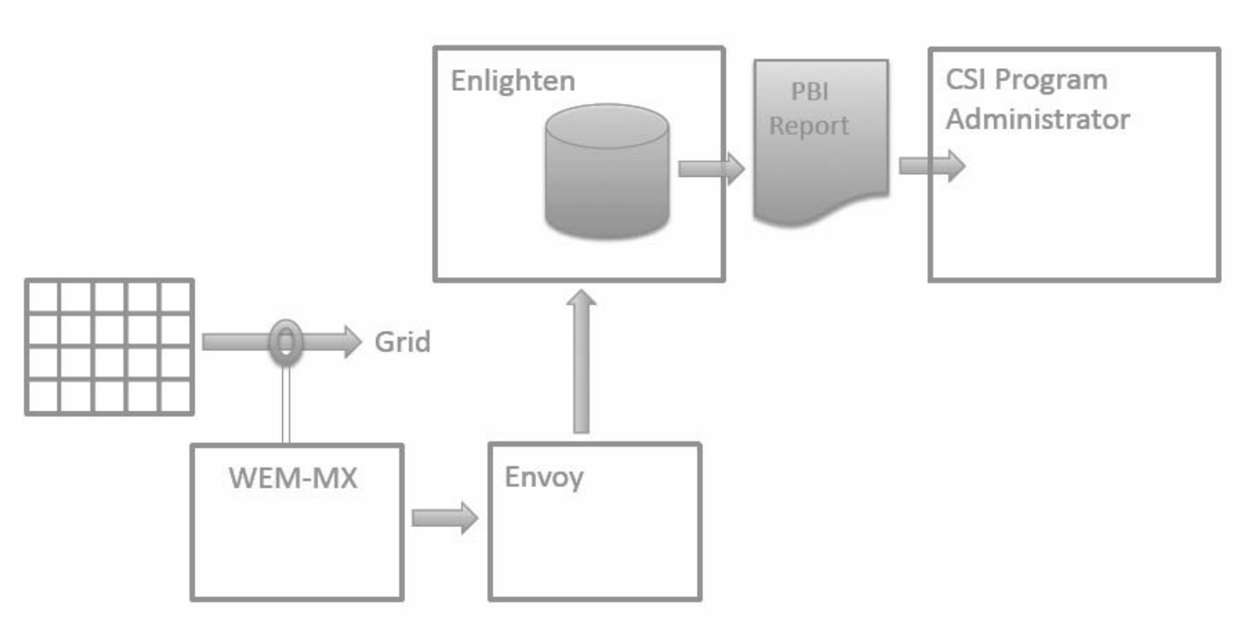
Vendor	Software / Firmware Upgrade Procedures	Warranty Offerings	Service Guarantees	Other Practices / Services
1	Software is updated remotely through the internet connection. So far we have not charged for any software upgrades.	NR	NR	NR
2	NR	NR	NR	NR
3	Embedded datalogger firmware can be remotely upgraded. Server side software is maintained by the PMRS/PDP IT staff.	Lease and PBI customers receive monitoring service for the full term of their contract (typically 15 years for leases). Cash customers receive a 5 year warranty.	PMRS/PDP provides guarantees of system uptime and performance for lease customers. Customers are reimbursed for production downtime and underperformance.	PMRS/PDP provides warranty repair and service calls as needed for all customers.
4	NR	We warranty all products and services for the duration of the service contract	NR	NR
5	NR	NR	NR	NR
6	Continuous and automatic web-based, no charge	All systems have 5 year warranty. Extended 5 year warranty available for $200 a year (two meter system)	PMRS/PDP network available 99.99%, local embedded computer maintains data whenever network is down for 1 minute samples for up to one year. Included in subscription.	None
7	NR	NR	NR	NR
8	Remote software upgrades. Firmware upgrades in manufacturing or during onsite support.	1 year warranty. Shark-100 meter 4 years from the manufacturer	Service Level Agreement on a customer by customer basis.	warranty repair, emergency services, service calls, commissioning support, installation training.
9	NR	NR	NR	NR
10	Firmware upgrade remotely (typically at no cost), other software tools are web based	5 year standard included in purchase price, extended warranties available (cost varies based on length of warranty), irradiance sensors need to be calibrated every two years.	None at this time	General maintenance to keep sensors clean and free of debris, $1000/day
11	Upgrades are provided at no cost for systems under warranty, and automatically downloaded.	Inverter with integral meter includes 15-year standard limited warranty at no additional cost. No extended warranties are offered. Monitoring system includes 1-year limited warranty. No extended warranties are offered. Energy Tracking meters are warranted by the manufacturer.	NA	NA
12	If required, firmware must be updated by PMRS/PDP as a T&M work order.	Manufacturer's warranty	NR	NR
13	NR	Equipment standard manufacturers warranty 5 year contract	NR	NR

6.4.5 System Diagrams

On the following pages, we provide simple block diagrams that were obtained directly from PMRS/PDP providers or the public domain. Each of these diagrams is vendor specific, but is not necessarily the systems offered by PMRS/PDP respondents to protect their private information. Instead, they are provided to illustrate the various types of PMRS/PDP systems in use, which are discussed in Section A.

This system shows a basic output monitoring and reporting system with a revenue-grade meter in the output and a communication channel through the PMRS system components.

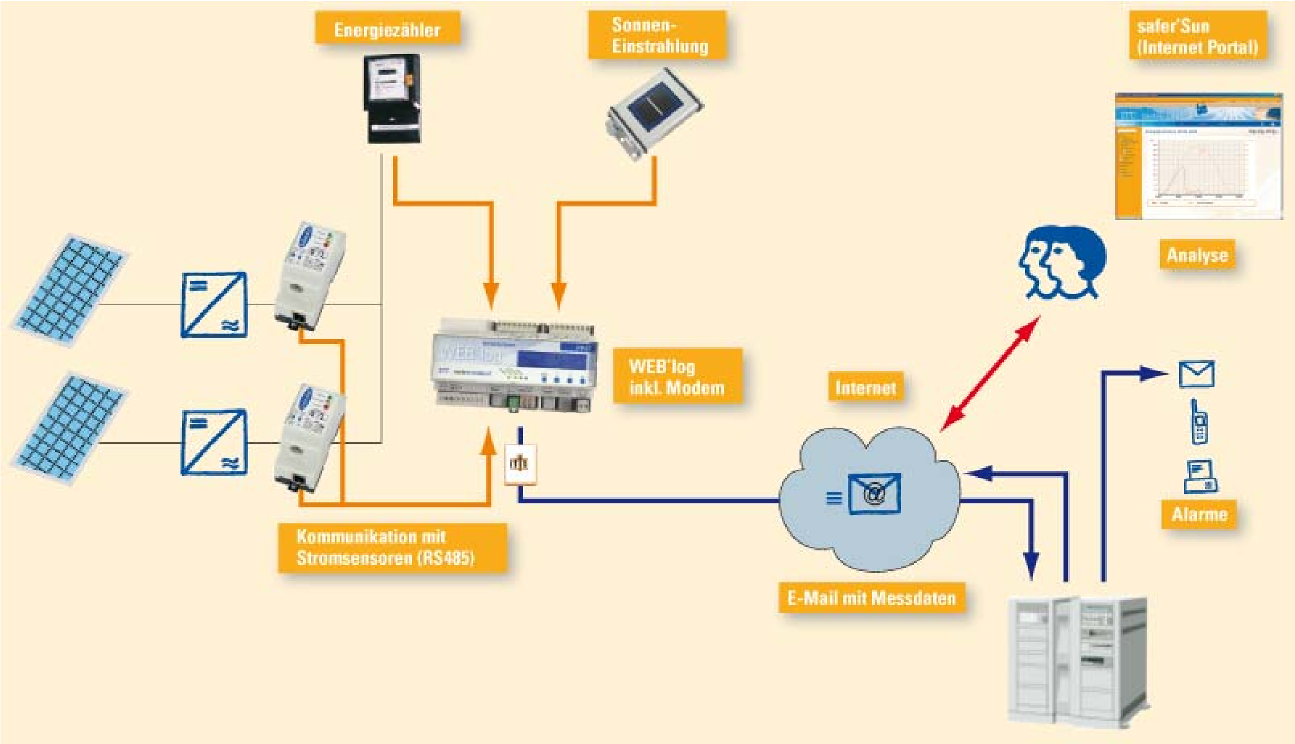
Figure 6-1: Enphase PBI Block Diagram



Source: Enphase Energy, Inc.

This is a system with data logging and analysis capabilities that alert a user in the event of system malfunction. There is no weather monitoring shown; it merely reads and analyzes the system output from the inverter.

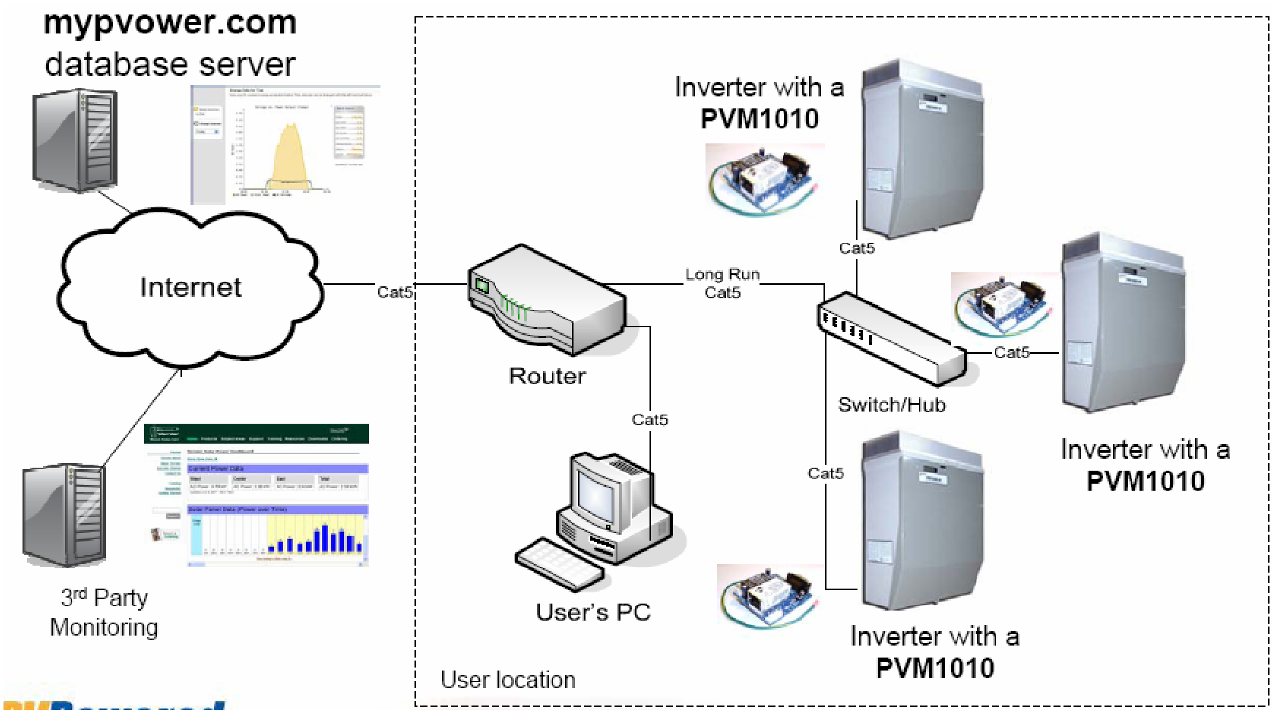
Figure 6-2: Meteocontrol Gmbh Monitoring System



Source: http://www.pge.com/mybusiness/energysavingsrebates/solar/csi/expopresentation/index.shtml

The PV Powered system can aggregate the outputs from several PV Powered inverters into a single data set for remote viewing by the end user, and for storage into a central server, which can then be viewed by authorized third parties.

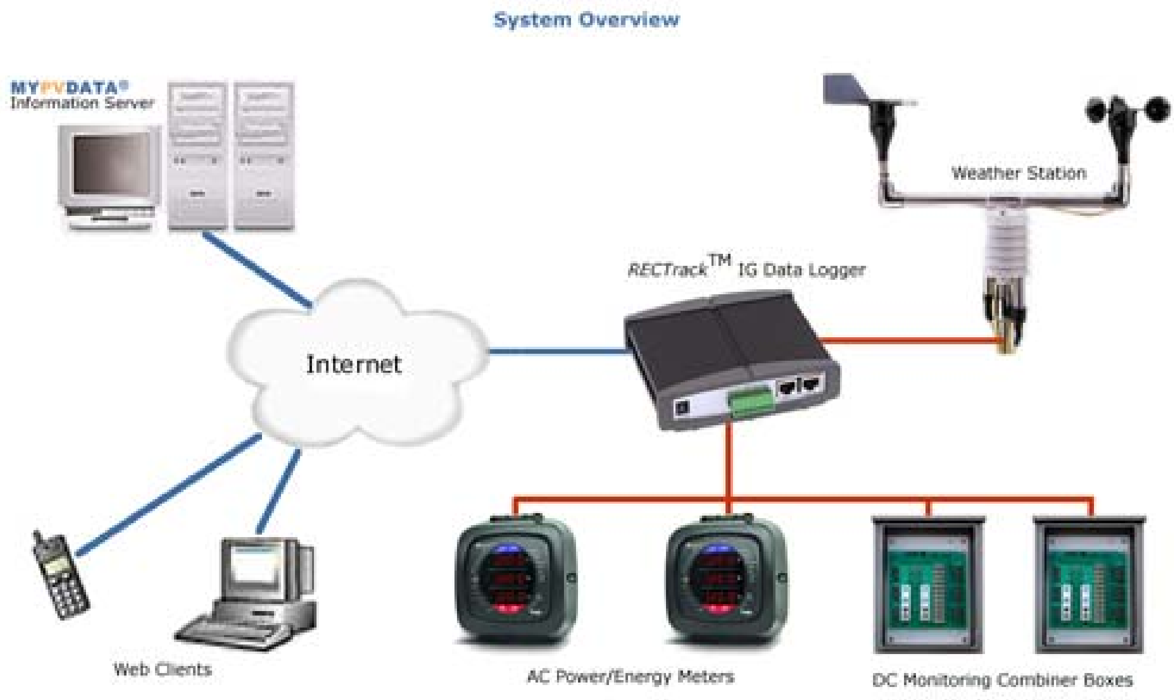
Figure 6-3: PV Powered Data Monitoring System



Source: http://www.pge.com/mybusiness/energysavingsrebates/solar/csi/expopresentation/index.shtml

The Energy Recommerce system shown includes monitoring of local weather conditions, DC power from the PV arrays, and AC output. The data is collected via a data logger and is then made available for recording to a central server, and remote viewing through PC display or cell phone.

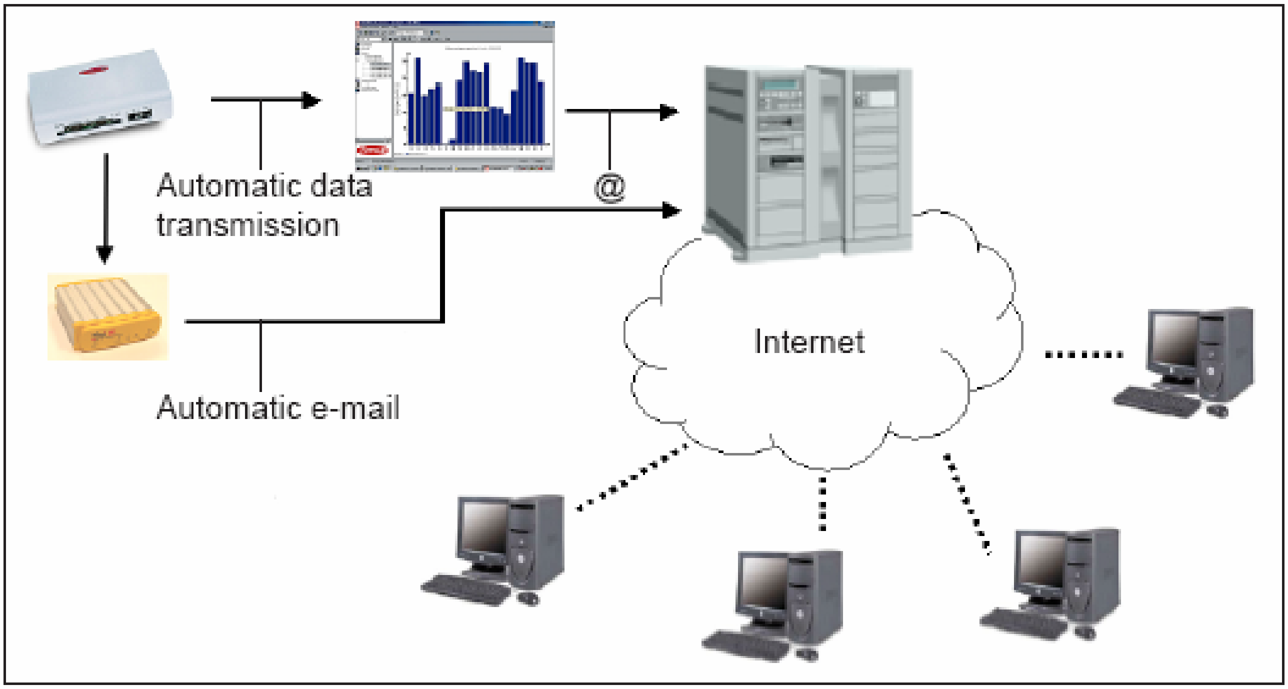
Figure 6-4: Energy Recommerce System



Source: http://www.energyrecommerce.com/index.php?fuseaction=products.home

The Fronius system interfaces with Fronius inverters for local viewing at the customer's site or transmission to a central server for remote viewing by authorized clients.

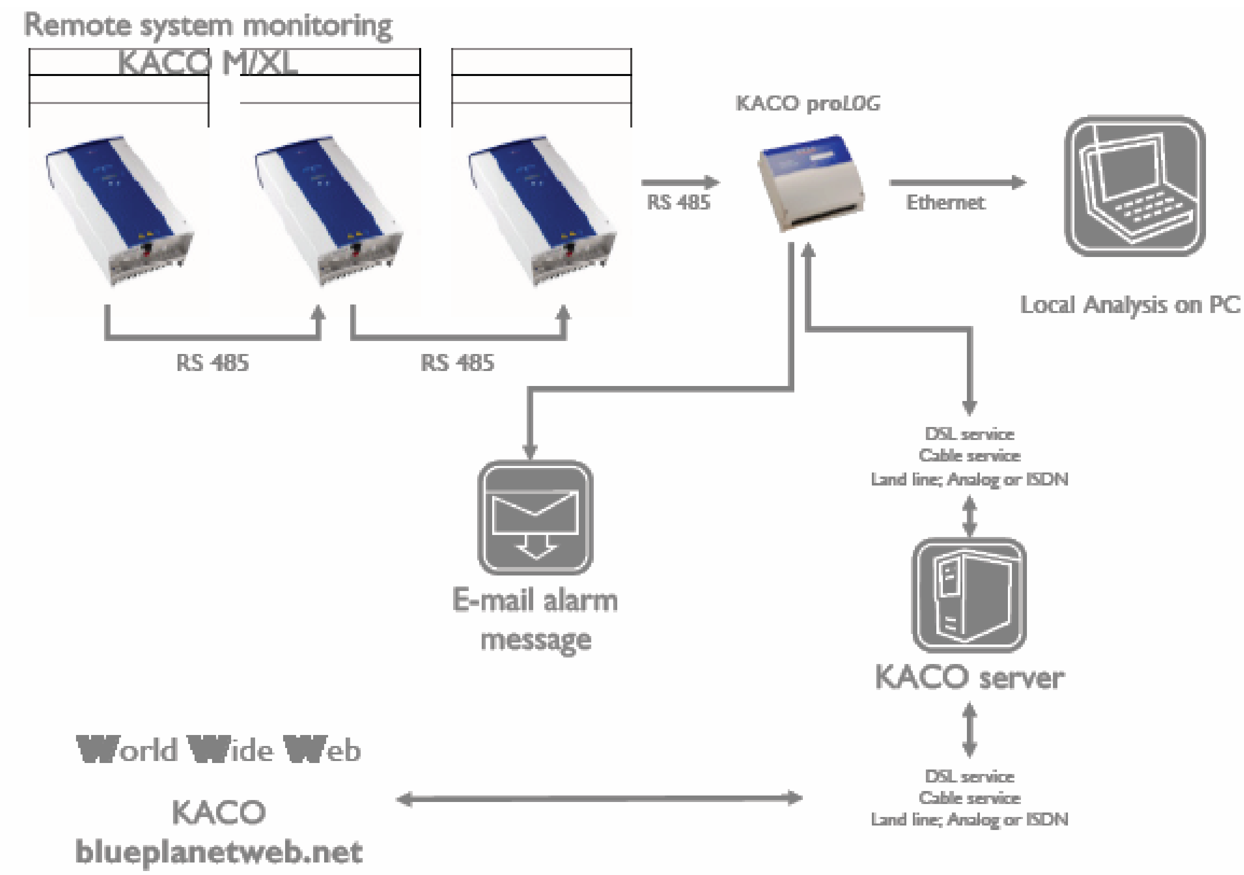
Figure 6-5: Fronius Solar Web System



Source: http://www.fronius.com/cps/rde/xchg/SID-8614DDD5-A0EEA604/fronius_usa/hs.xsl/2714_2150.htm

The KACO system is an interface to KACO inverters for local display, storage onto a central server, and e-mail alerts should a malfunction occur.

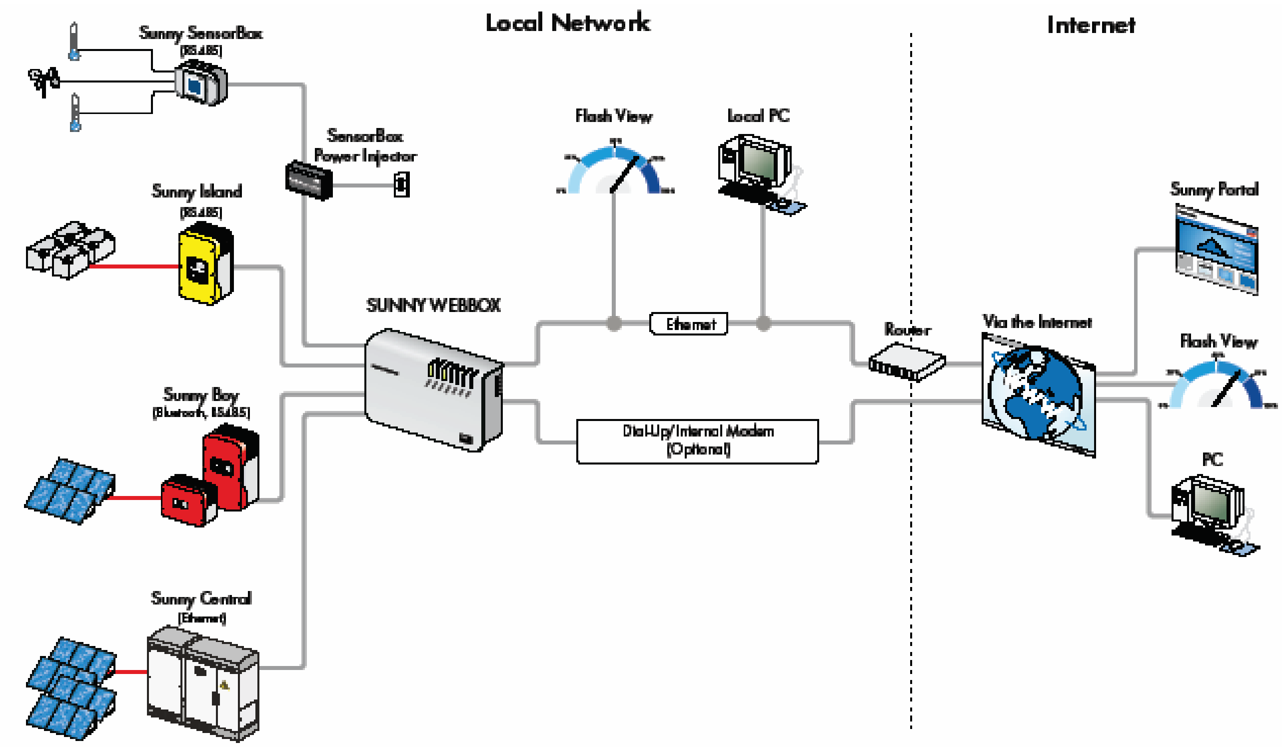
Figure 6-6: KACO proLOG Monitoring System



Source: http://www.kacosolar.com/Accessories.php

The SMA SUNNY WEBBOX System includes a wide range of options. There is a basic interface to building-scale SMA PV inverters and central- or community-scale PV inverters, weather stations, and battery storage systems. The data is collected and made available for local display or web-based display for remote viewing by authorized users.

Figure 6-7: SMA SUNNY WEBBOX System



Source: http://www.sma-america.com/en_US/products/monitoring-systems/sunny-webbox.html

7. Section E – Compare CSI Requirements with Hardware Labor and Service Offerings

7.1.1 Objectives

This section addresses the quantification, categorizes, and compares the various performance meter offerings currently included on the CSI list of eligible equipment. It also addresses the effects of CSI PMRS cost caps on the product offerings and evaluates whether the cost caps are too restrictive.

7.1.2 Background and Significance

To date, there are over 400 metering devices included on the CSI-eligible equipment listing. Many are certified to ±2 percent accuracy and others are self-certified by the manufacturer to within ±5 percent.

An evaluation of PV systems installed under the CSI as of April 2009 shows out of 14,287 residential systems, 164 were PBI and the rest were EPBB. The average residential system size is 5.3 kW-DC. For the commercial sector (including government and non-profit), 981 systems have been installed, 260 were PBI and the rest were EPBB. The average system size for this sector is 138 kW-DC.

The CSI Program requires that PMRS systems are installed on PV systems unless an owner can demonstrate that the cost of the metering system would exceed the CSI cost cap. Based on incentive structure and installed PV system output, these cost caps cannot exceed a specified percentage of total PMRS system cost to be eligible for the incentive. All PBI systems must have a PMRS service, with an output meter accurate within ±2 percent, administered by a PDP. EPBB systems must have at least a ±5 percent meter with a local display only if evidence shows that a PMRS service would exceed the cost cap. If the cost cap would not be exceeded, a ±5 percent meter (at least) with PMRS service must be provided.

Cost caps are as shown in Table 7-1.

Table 7-1: California Solar Initiative Cost Caps

Incentive Structure	System Size	Minimum Meter Accuracy	PMRS Required	Cost Cap
EPBB	< 30kW	± 5%	Yes	1%

EPBB	30 kW and greater	± 5%	Yes	0.5%
PBI	All	±2%	Yes	No Cost Cap

Source: California Solar Initiative Handbook, November 2008

Prior to this study, an evaluation of cost cap impact had not been performed.

7.1.3 Research Design and Methods

KEMA performed a survey of PMRS/PDP providers as discussed in Section A. The survey asked questions about system costs and the CSI metering cost cap. PV installation costs were researched by reviewing the PV system incentive applications posted on the CSI website. This research revealed the number of systems that would exceed the cost cap for both systems under 30 kW and between 30 kW and 50 kW.

KEMA also researched PMRS product offerings, certifications performed on metering systems, and pricing for system output meters included on the CSI-eligible equipment listing.

7.1.4 Research Results – Cost Cap Evaluation

Based on research findings, KEMA determined a basic PMRS service will cost approximately $3,000. Many PMRS/PDP providers offer additional services other than simply output metering for an additional price. But at the lowest end, basic service is approximately $3,000 for hardware, installation, and monitoring service for five years. Some systems are less expensive. For example, some inverter manufacturers will provide free PMRS service should a customer purchase their inverter products. Some inverter manufacturers will charge a few hundred dollars to include the service. But several independent PMRS providers will typically charge approximately $3,000 for service. Figures 7-1 and 7-2 illustrate the distribution of total system costs from the CSI database based on:

- Systems below 30 kW with a 1 percent cost cap
- Systems between 30 and 50 kW with a 0.5 percent cost cap.

The systems evaluated were downloaded from the CSI database on 5/9/09. The systems included in the evaluation show a status of completed, pending payment, or PBI – in payment. There are many other systems in the CSI database with a different status level, but this evaluation included only actual installed projects.

Assuming the PMRS service is $3,000:

- 14,785 systems below 30 kW were evaluated. Of these, 8 systems, or 0.05 percent, fall within the 1% cost cap and would require PMRS service. The remaining systems would not require PMRS service.
- 115 systems between 30 kW and 50 kW were evaluated. Of these, 3 systems, or 2.6 percent, fall within the 0.5% cost cap and would require PMRS service. The remaining systems would not require PMRS service.

For a simple residential system with a single inverter, where the PMRS is tied to a single inverter reading the inverter integral meter, the system cost may be less than $3,000. Some cost quotes received from CSI program administrators gave cost quotes of approximately $1,000. Assuming a $1,000 cost for systems below 30 kW, 640 systems, or 4.3 percent fall within the 1% cost cap, which is still a very small number.

Figure 7-1 shows that 1% of system costs begin falling below $1,000 at approximately 15 kW. Of the 14,785 systems below 30 kW, 14,532 (or 98%) are below 15 kW. This illustrates of what several PMRS providers have been complaining. They receive a large number of requests for PMRS quotes as evidence that PMRS service is not required due to the cost cap.

In the PMRS/PDP web-based survey, each respondent was asked if a different cost cap would be appropriate. No respondents directly answered this question. One provider recommended that all systems should be eligible under a PBI structure. Three other providers (through phone conversations) recommended a better integration of PMRS service into the program. Each respondent noted there was value in PMRS service by identifying under-performing systems. It is difficult to quantify this value in additional kWh generated, (or in lack of generation should the service not be installed) but there is value to this service that should be quantified and integrated into the CSI incentive structure.

Some PMRS providers expressed frustration about providing cost quotes to simply document cost cap excesses. Many cited that the need to document costs exceeding the cost caps has created undue work for metering providers and manufacturers.

Figure 7-1: 1% Cost Cap

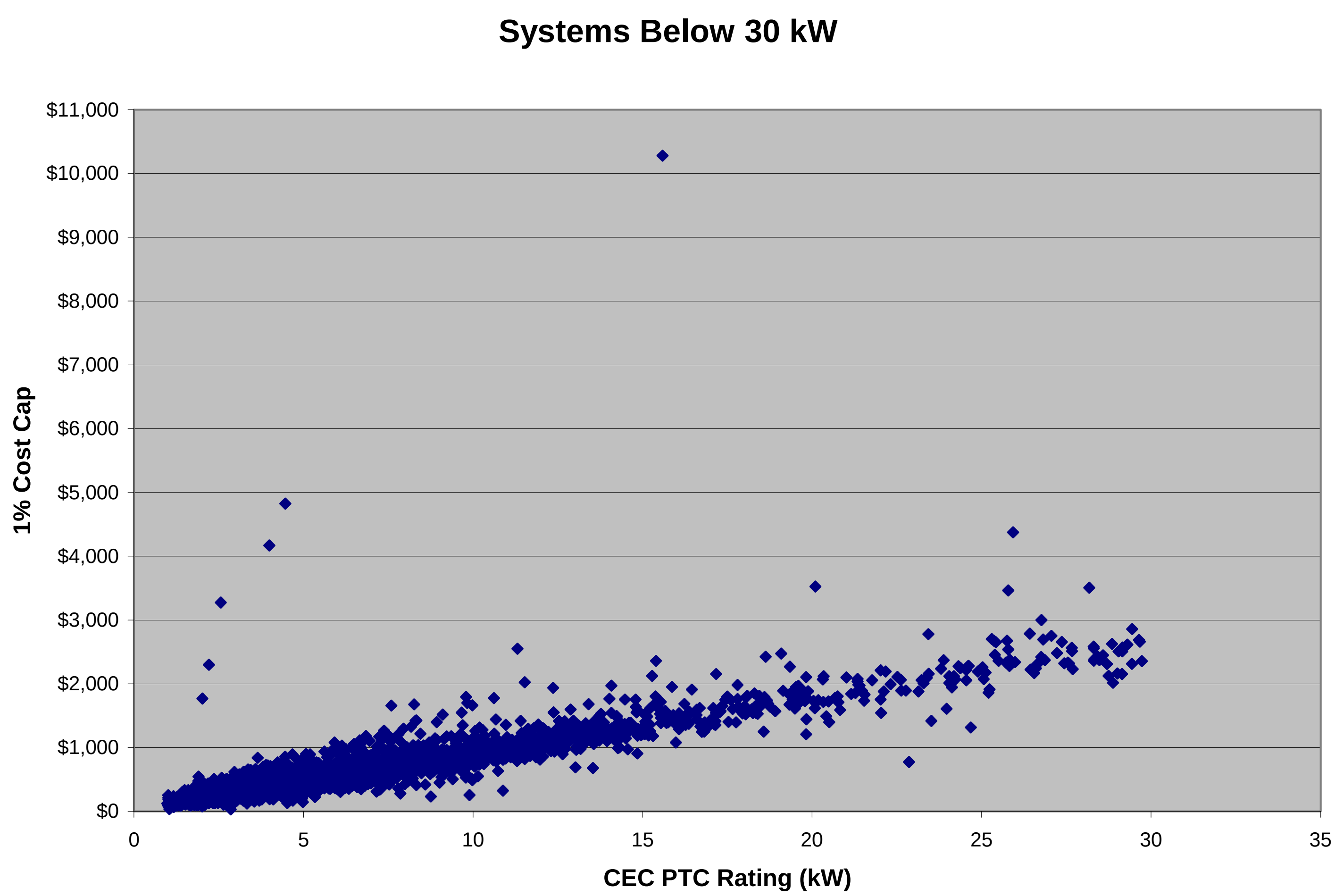
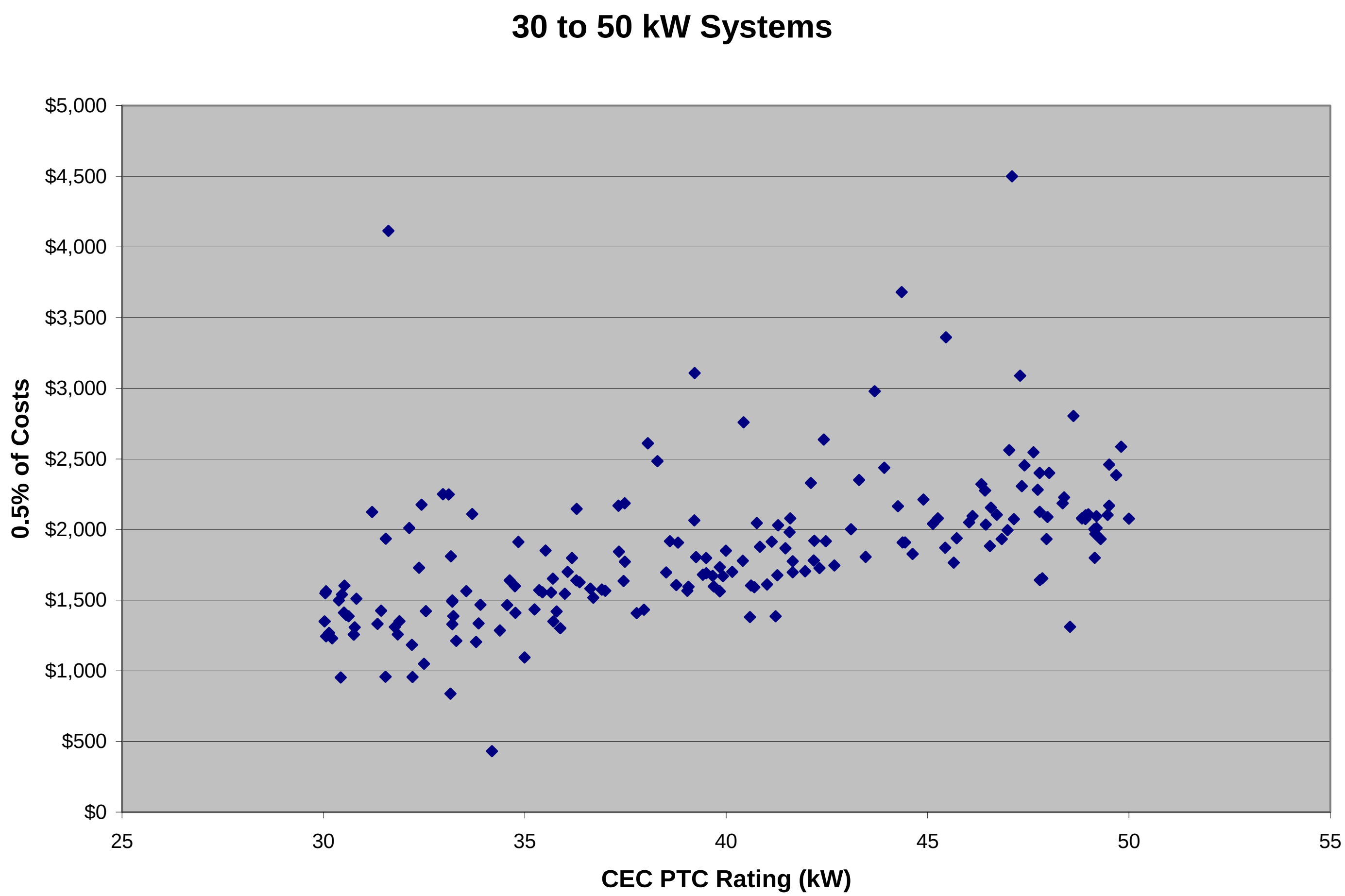


Figure 7-2: 0.5% Cost Cap



7.1.5 Research Results – Meter Product Offerings

Metering product information was collected on the majority of meters included on the CSI-eligible meter list. At the time of this study, 417 meters and metering systems are included on the CSI listing. Ten manufacturer's products comprise 355 or 85 percent of the eligible meter listings.

Meters meeting the ±2 percent accuracy requirements, typically complied with some version of ANSI C12. Schneider Electric has meters that have been certified to European accuracy standards, which include comparable accuracy classes to ANSI C12. Meters meeting ±5 percent accuracy requirements are self-reported by the manufacturer, and there are no specific standards for this accuracy class.

ABB/Elster and GE manufacture traditional socket type meters that can be used for utility billing purposes. Other manufacturers provide meters typically used for submetering purposes with current transformer (CT) interfaces to wiring systems. Schneider Electric manufactures both types of meters. All other meters included in the evaluation include CT interfaces.

Meter costs were obtained from internet searches and through direct contact with manufacturers and varied dramatically. Some meters are as inexpensive as $35 (a cyclometer type meter), but most meters cost between $200 and $500. Many of these meters are digital and can be used in PMRS/PDP systems. Of note, Schneider Electric meters vary greatly in cost based on system usage. For example, an ION6200 meter can cost from $450 to $650 without an integral display and from $600 to $800 with an integral display. Schneider Electric's ION8600, which is used to monitor substations, service entrances, and network interconnections can vary in price from $2,050 to $4,550.

In doing the study, it was found most manufacturers do not publish warranty information, and instead cited "call for warranty information." One possible reason for this evasiveness is that product life is highly dependent on correct design of the interconnection and correct installation. Therefore, if an unqualified installer installs a meter it in a manner that does not meet applicable codes, the manufacturer should not be required to honor any warranty for the product. However, some manufacturers do publish warranties. Electro Industries provides a 4-year warranty, and Integrated Metering Systems provide 10-year warranties.

A meter summary is provided in Table 7-2.

KEMA

Table 7-2: CSI Eligible Meter Products

Manufacturer Name	Description	No. with 2% accuracy	Price Range	No. with 5% accuracy	Price Range	Meter Type	Customer Type	Certificate	Warranty
Abb/Elster	Elster electricity meters are designed with a standards based architecture that is flexible and supports advanced communication solutions, metering automation systems, as well as demand response, home area network (HAN), and wide area network (WAN) applications. Elster's electricity meters are designed to meet international standards (IEC) as well as a variety of national standards (DIN, BS, VDEW, and ANSI). We offer meterse for single phase and polyphase serivces; and our meters are sold worldwide.	20	$105-$510	14	Prices not found	Socket	Res/Com	ANSI C12.1 ANSI C12.20	
Continental Control Systems	Continental Control Systems designs and manufacturers the WattNode AC power and energy meters. Available products include pulse-output watt-hour transducers and LonWorks power, energy, and deman meters. Applications include utility sub-metering, end-use metering, equipment performance monitoring, verification, evaluation and diagnostics.	0	NA	25	$198-$244	CT	Res/Com/Ind	NA	
Electro Industries	Electro Industries meters are known world-wide for their ease of use, advanced power functionality and reliable service. We offer a full range of products from the simplest single display power meter to the most sophisticated power meter with power quality and automation solutions. All our products offer a rich feature set combined with open and easy-to integrate communications.	5	$395-$695	0	NA	CT	Com/Ind	ANSI C12.20	4 years
Elkor Technologies	WattsOn universal digital power transducer uses cutting-edge metering technology to provide unprecedented accuracy and metering information for any electrical installation. WattsOn monitors each phase individually and incorporates the functions of single-phase, split-phase, and three-phase meters, to provide over 15 electrical measurements, per phase.	6	$153-$230	0	NA	CT	Res/Com	ANSI C12.20	
E-MON	Designed too install easily in new or retrofit applications, E-Mon D Mon meters father money-saving data for tenant and department allocation, analysis of energy usage patterns to identify failing equipment and inefficiencies, and metering and verification of facility conservation programs.	63	$351-$1,356	0	NA	CT	Res/Com/Ind	ANSI C12.1 ANSI C12.16	

Table 7-2: CSI Eligible Meter Products

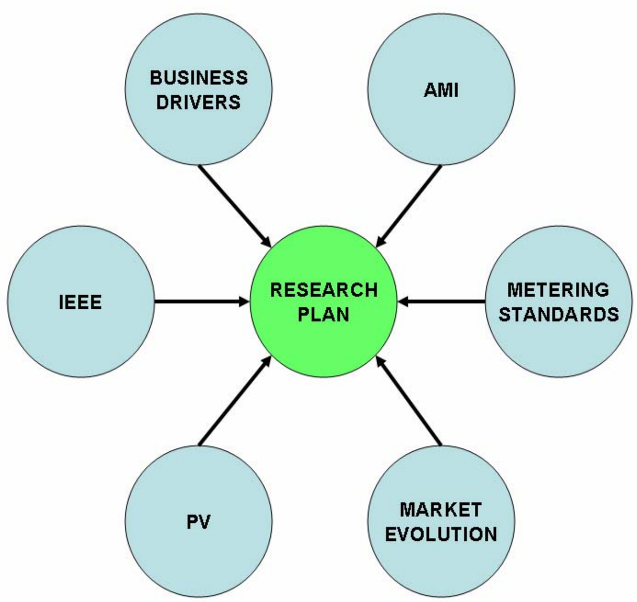
Manufacturer Name	Description	No. with 2% accuracy	Price Range	No. with 5% accuracy	Price Range	Meter Type	Customer Type	Certificate	Warranty
Energy Tracking	Our Web Enabled Meter (WEM-MX) is a revenue grade 4-qudrant Internet enabled electric meter with advanced communications for energy management. This advanced energy meter can provide consumption and demand data as well as interval data (load profile) and by time of use. It is available in single phase, two phase and three phase configuration. It reports data via its built in webserver, e-mail, ftp or SOAP Web Service client.	22	$800-$900	0	NA	CT	Com/Ind	ANSI C12.20	
GE	The advanced, powerful and easy-to-use meters give you an extra edge in the energy business.With the lines between utility, industrial and commercial metering disappearing, our meters offer slutions beyond revenue metering. You can look forward to real-time instrumentation, power quality monitoring and accessing critical information. All these add up to give you higher productivity, improved efficiency and reduced energy costs.	11	$35-$299	0	NA	Socket	Res/Com/Ind	ANSI C12.1 ANSI C12.10, ANSI C12.20	
Integrated Metering Systems	IMS has been manufacturing 1-phase, 2-phase and 3-phase electric submeters since 1989 for apartments buildings, shopping centers, hospitals, universities, office buildings, industrial applications, marinas, campgrounds, alternative energy and other electric metering applications.	144	$280-$530	0	NA	CT	Com/Ind	ANSI C12.1	10 years
Schneider Electric	Schneider Electric offers a full portfolio of metering and monitoring products and solutions, scaleable from simple metering and analysis to remote, online enterprise wide power management solutions. Whether you are an energy supplier, or consumer, our intergrated solutions provide the tools to deliver fast and quantifiable payback by helping you to manage the quality and cost of your energy.	6	$450-$4,550	0	NA	Both	Res/Com/Ind	ANSI C 12.20 IEC 62053 IEC 61000 IEC 60687 EN55014 EN61000	
Veris Industries	Veris offers a complete line of power monitoring devices perfect for tenant submetering, chiller optimization, demand management, critical load and management, and energy conservation.	39	$540 -$840	0	NA	CT	Com/Ind	ANSI C12.1	

8. Section F – Integration of CSI Metering Requirements and AMI

8.1 Introduction and Objectives

This part of the research will identify factors affecting the potential convergence or divergence of AMI and solar system metering as ways are identified to integrate the metering data and provide support for common business systems. The specific objective is to determine the most effective way of merging and integrating these two areas of technology into an efficient system that leverages the best attributes of both and minimizes duplication of effort in areas such as billing, operations, and maintenance. This will start by identifying and evaluating the requirements and systems used for AMI and PMRS/PDP metering.

Figure 8-1: Incorporating many Industry Drivers.



Integrating metering requirements purely within AMI can be challenging, because it requires analyzing current integration standards (formal and de-facto) as well as vendor-specific technologies and capabilities. Suitable best- practice features can be integrated while leaving room for emerging trends. For instance, not all vendors offer the same metering capabilities; some that support identical business functions may have proprietary data formats. This suggests that a common format needs to be developed that will support integration, accomplished by reviewing current formats, emerging standards, and through discussions with technology vendors in the AMI and PV markets.

This section describes the AMI technology, including various options of data communication available in the marketplace and interfaces with other technologies at customer locations to take advantage of the investment. It further discusses how services provided by PMRS and AMI differ or overlap and how they can be integrated to meet current or future needs. Section 8.2 describes business drivers for metering solar generation while 8.3 through 8.7 describe the AMI technology. Sections 8.8 to 8.10 address services offered by PMRS and AMI, including cost, integration, and PMRS and AMI overlaps. As major utilities in California provide AMI for their customers—and it will take a number of years—it will lead to the eventual development that all consumption meters will be read through AMI, this report assumes.

8.2 Business Drivers

Even though different vendors may utilize similar technologies and offer similar capabilities and functionalities, each particular solution is designed to support specific throughput and capacity. These solutions depend on the communication technology adopted and implementation approach chosen by the vendor, whether for AMI or PV metering. This section provides an assessment of how AMI and solar systems could be best integrated through the use of common technologies and/or standardized data transfer requirements. This section also evaluates how the AMI programs of California's three investor-owned electric utilities can be leveraged to support PMRS/PDP, noting similarities and differences in approach and how these factors could affect the integration with PMRS/PDP. Table 8-1 provides an overview of business drivers and associated requirements and/or considerations.

Table 8-1: Solar and PMS Business Drivers

Business Drivers for installation of solar meters and Performance Monitoring Services	How is this objective met?	Why this is required?	Who are the beneficiaries?	Comments	Consideration
INCENTIVE PAYMENTS: Payment for solar generation incentive under EPBB	5% accurate meters are installed – PMRS/PDP service may not be included if the cost of this service exceeds 1% of the total cost for systems below 30KW (or 0.5% for system >=30KW)	Customers may monitor the performance of the solar system.	Customers		
INCENTIVE PAYMENTS: Payment for solar generation incentive under PBI	Interval data metering systems with more than ±2% accuracy must be installed and monitored for 5 years. Data is being provided to utility (program administrator) through EDI.	Incentive is paid on the performance of the solar system. Monitoring system provides real-time solar performance to the customer through web.	Customers		

Business Drivers for installation of solar meters and Performance Monitoring Services	How is this objective met?	Why this is required?	Who are the beneficiaries?	Comments	Consideration
VALIDATION: Knowledge of how much generation is being produced by solar, if incentives are having any impact. M&E (Measurement and evaluation) of the plan.	PMRS/PDP of record are asked to provide data by CPUC for the monitored systems. Unmonitored systems will need to be audited when CPUC requires program evaluation.	Post installation validation of assumptions, cost benefit studies, and future program designs.	California Public Utilities Commission (CPUC)-CSI Utility CA State	Gathering meter data, even for EPBB-type meters, will facilitate meeting M&E requirements.	CSI requirement leaves many small installations without remote monitoring, which increases the cost of measurement and program evaluation.

Business Drivers for installation of solar meters and Performance Monitoring Services	How is this objective met?	Why this is required?	Who are the beneficiaries?	Comments	Consideration
MEASUREMENTS: Calculating RECs	EPBB with no revenue-grade solar meter will only receive RECs if energy is sent back through net meter; installing revenue-grade meter for solar generators will be effective way to receive credit for all of the energy created through PV. For PBI, as meters are installed and monitored, RECs can be easily counted. Since utilities are required to purchase 20% of energy from renewable resources by 2010, they may want to purchase them from solar system owners.	Green House Gas (GHG) reduction, cap and trade regulation.	Utility Customers CSI	Gathering meter data for EPBB-type meters will facilitate calculating RECs.	Recommend adding monitoring for smaller systems.

Business Drivers for installation of solar meters and Performance Monitoring Services	How is this objective met?	Why this is required?	Who are the beneficiaries?	Comments	Consideration
MAINTENANCE: On-line solar system monitoring. Communicating maintenance issues to service providers.	Manually monitoring or charting the smaller systems that are not monitored by PMRS/PDP, performed by customer. Automatically monitoring solar panels and providing alarms in near real time for larger systems.	Longer solar system operating time will improve performance and ROI. Monitored system providing alarms for performance degradation can be repaired in a timelier manner and produce more energy over time.	Customers CSI Utility		Studies should be conducted to evaluate how long solar systems were out of service because they were not continuously monitored.
MONITORING: Online near real-time monitoring of energy production.	Integrating solar meter with AMI metering will provide remote visibility of solar system with the net meter. Owners of larger systems may buy near real-time monitoring service for solar meters through PMRS.	If meter is not monitored and integrated with AMI, utility may not know if solar system is working over a certain time period. Online solar metering may be helpful if utilities are purchasing RECs.	Utility Customer	Currents requirements do not allow visibility into customer side of the generation (no real-time monitoring provided to utility), which may create grid-operations problems if solar penetration increases.	Monitoring of voltage, KVARh in addition to the KW and KWH, may be needed if solar system penetration increases to high level.

Business Drivers for installation of solar meters and Performance Monitoring Services	How is this objective met?	Why this is required?	Who are the beneficiaries?	Comments	Consideration
FORECASTING: *Integration with Load and Energy Data* Load forecasting for supply or resource planning. Demand and energy reduction calculation for any given day while keeping track of customer load changes.	Three items need to be measured at customer location: load, utility input, and solar generation. All three will be available if two of the three are measured and monitored. This can be accomplished by monitoring two meters.	Better estimation of day-ahead or real-time analysis can be achieved if both load and generation data is available. Note that financial benefit for monitoring extra meter may not be perceived high enough to utility, since net meter provides enough data for utility operations.	Utility	Current requirements do not allow visibility into customer side of the generation (no real-time monitoring provided to utility), which may create grid-operations problems if solar penetration increases.	
GRID OPERATION: Smart grid applications and integration	Metering and data capture capabilities are the fundamental building blocks for smart grid applications.	Reliability improvements and customer satisfaction. Ability of utility customer service personnel to analyze customer issues.	Utility State Customers	Gathering meter data for EPBB-type meters will facilitate utilities providing better service to their customers.	

Business Drivers for installation of solar meters and Performance Monitoring Services	How is this objective met?	Why this is required?	Who are the beneficiaries?	Comments	Consideration
ENERGY SAVINGS: Building control integration with utility meters and incentives for energy reduction vs. energy production.	By installing meters that communicate with each other and utility systems.	Utility may want to separate incentives for solar vs. load reduction during high demand times. Most likely, utilities will be interested in net consumption reduction during peak-demand time, but customers may respond to additional incentives for load reduction in addition to solar generation.	Utility State Customers	Gathering meter data for EPBB-type meters will facilitate utilities' ability to further reduce demand and energy consumption.	Monitor all solar systems

Business Drivers for installation of solar meters and Performance Monitoring Services	How is this objective met?	Why this is required?	Who are the beneficiaries?	Comments	Consideration
GRID OPERATIONS: Solar systems on distribution networks	When a utility interactive inverter is installed in a system with a net meter, it is presumed that energy *could* be exported to the grid. In such cases, solar system monitoring and control by the grid operator may be desired.	There is a push to get solar installations on distributed networks. Typically, PV systems would not generate more than the customer load (such a scenario can be evaluated during the interconnection agreement with the utility). But to diagnose network-protector tripping issues, it may be beneficial to monitor solar as well as net meters.	Utility State Customers	Gathering meter data for EPBB-type meters will facilitate utilities' ability to diagnose power system distribution-network-related issues.	Monitor all solar systems

The implementation of AMI systems provide many different functions and benefits to utilities and customers, including:

- The flexibility to introduce new rates, based on interval data and time of use
- New billing options, including web customer portals
- Meter reading improvements (both accuracy and collection efficiency)
- Increased awareness of energy use, demand, voltage, and power quality
- Two-way communication, outage information, faster utility crew response, and remote customer disconnection
- Potential communication to customer devices, like thermostats, to facilitate price signals decisions, thus reducing customer costs. Such an interaction must be approached with care to avoid creating customer problems and/or complaints.
- Load forecasting, feeder design, daily operation and smart-grid applications, information for phase-balancing improvements, transformer load management, and distribution planning
- Energy-efficiency improvement, demand reduction, and so forth through real-time price signaling or tariff applications.

Utility AMI systems are being installed for all classes of customers with differing standards and provide data in different formats than PMRS/PDP for solar initiatives. Monitoring services for solar generation may only be available for larger systems (>30 kW), where they are required to provide metering data from the inverter in order for the customer to receive incentive payments. Data is provided once a month to the utility through PMRS/PDP, whereas AMI collects data every 15 minutes. Typically, AMI systems collect interval data every hour for small loads (e.g., residential) and at 15-minute intervals for larger loads. This data can be collected by the AMI head end, then to the meter data management (MDM) system at regular intervals ranging from several times a day to daily. The data collection frequency will depend on the size of the load and the need to monitor it. PMRS/PDP data is collected at 15-minute intervals, but is retrieved from the PMRS/PDP servers at intervals of near real time to daily, but is delivered to utilities once a month.

Even though installed solar metering systems (at least for PBI applications) are required to provide data, the use of data is for paying incentives. Meters installed for these purposes may have many or all the capabilities of meters installed by the utility, at least from a metrology perspective. Unless they are integrated with the utility AMI data collection systems, their potential use for the long-term benefit may be limited, requiring use of two separate systems for collecting data, which then must be integrated for any analysis that involves both sets of data.

Meter data for each of the solar sites monitored by PMRS/PDP is required to provide data to each administrator through EDI 867 protocols once a month. Each administrator is setting up a different process to collect this data. SCE plans to receive the data and to manage incentive payment processing through their internal resources, while PG&E and CCSE will outsource this process. PMRS/PDPs are required to follow each administrator's rules and processes.

8.3 Advanced Metering Initiative Technologies used in Three California Utilities

AMI, in general, consists of meters that can provide interval data through communication technologies to a centralized MDM system. MDM systems generally interface with utility back office systems to provide the full benefit of interval data. AMI is a key component in the utilities' vision to create a smart grid along with substation automation, supervisory control and data acquisition (SCADA), and the deployment of intelligent electronic devices (IED), such as reclosers, relays, capacitor bank monitors, breaker monitors, etc.

8.3.1 Meter Functionality

Meter functionality is rapidly converging across the suppliers to formulate a "*typica*l" set for residential and light commercial meters. The most common features (available from several suppliers) have the following general functions:

- Interval recording of watt-hour usage, with non-volatile storage from several days to one month
- Interfaces to communications hardware (such as radios or power line carrier) or built-in ("*under glass*") communications facilities
  - Compatibility with emerging communications standards, including ANSI C12.22
  - Remote download of meter firmware revisions and reprogramming commands
- Interfaces to devices at the site such as:
  - Home-area network interface
  - In-premise customer displays
  - Collection of gas and water consumption data as a contract service to other utilities
  - Controllable end-use devices, such as electric water heaters, air conditioners

- Load disconnect switches rated at 200 A. The switches optionally include:
  - The capability to limit current draw, so that service can be turned off
  - "*Soft*" turn-on, such that the service is immediately disconnected if a high current draw is sensed on the load side upon the command to reconnect
- Notification of power outage conditions with a short keep-alive capability ("*last gasp*") to allow the meter to report for a few minutes after incoming power is lost. (This also allows a meter communicating via radio frequency (RF) to report if it has been removed from its socket.)
- Tamper and theft notification
- Bi-directional metering wherever alternative energy sources, like wind or solar, are installed for net metering purposes.

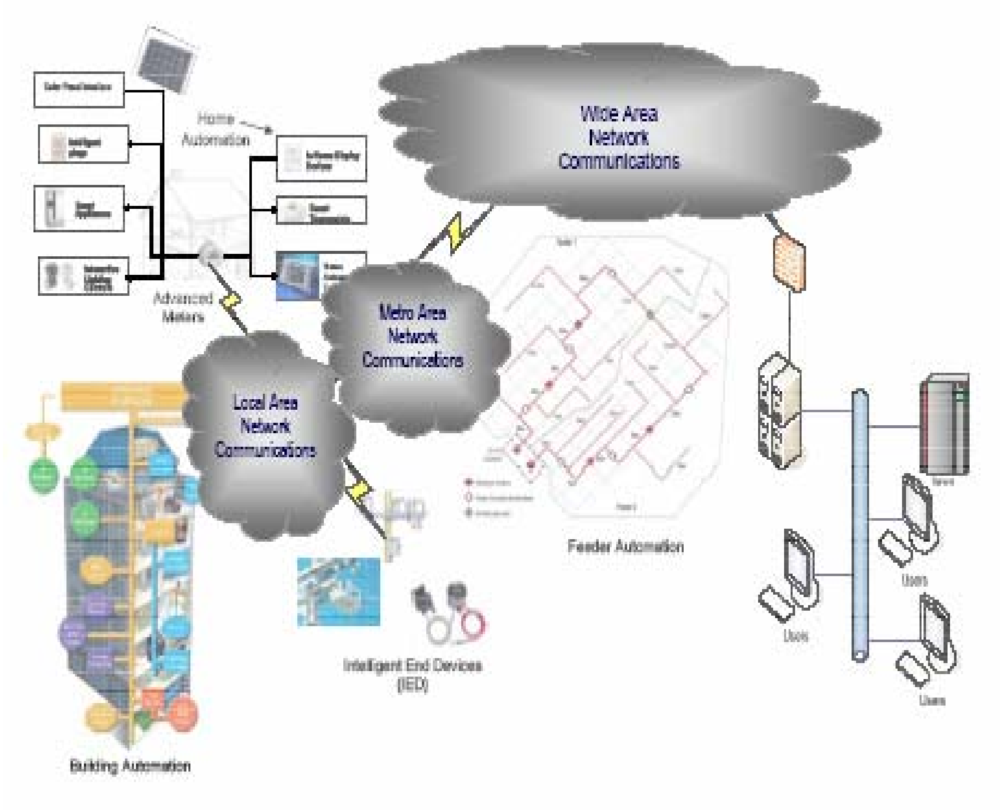
The following function set (in addition to above) is provided in self-contained commercial and industrial meters:

- Usage reading and storage with additional capabilities for reactive power, power factor, multi-phase service, and power quality
- Interfaces to communications facilities
- Interfaces to devices at the site, extended to include interfaces to customer energy control systems.

8.3.2 Communication Networks

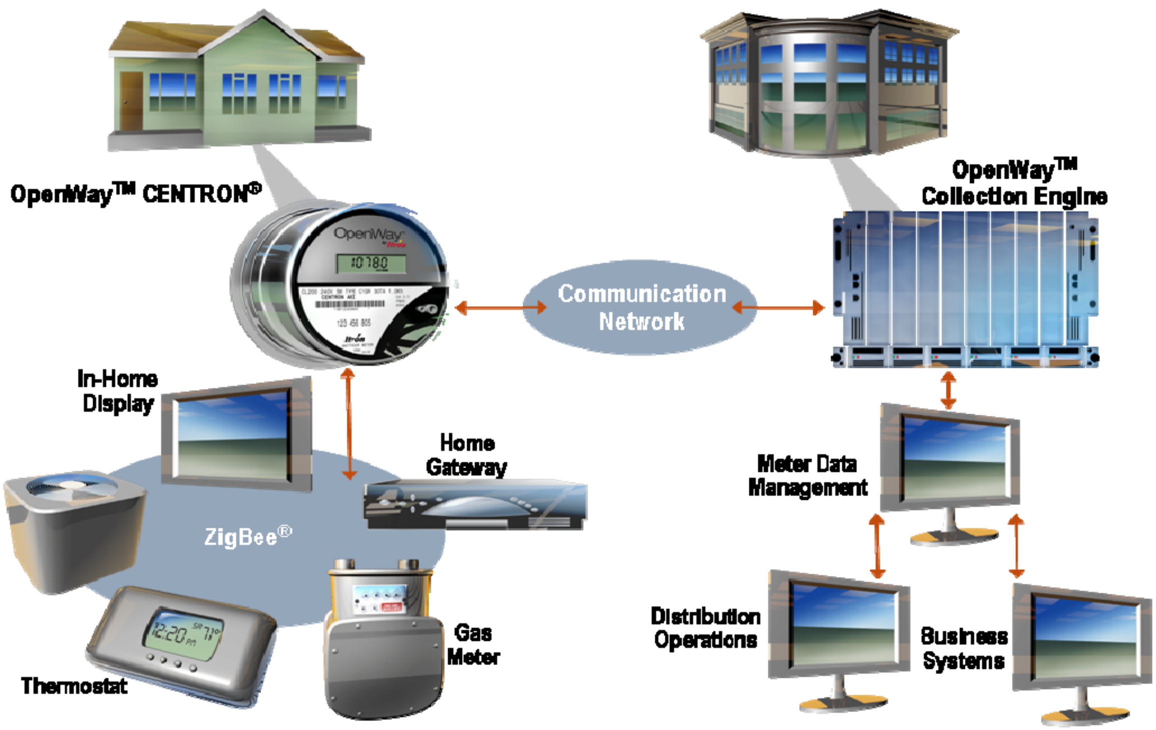
In Figure 8-2, we have provided an overview of a typical PV communications' network.

Figure 8-2: PV Communication Network



In Figure 8-3, several communications' technologies and their functionalities are illustrated.

Figure 8-3: Example of Communication Network



8.3.3 Definition of Technology

The communication infrastructure for smart grid, which includes AMI, incorporates networks that relay digital data bi-directionally between the utility and consumers. A local area network (LAN) is typically used to transmit digital usage readings from on-site meter interface units (MIUs) to data collectors. The collectors then store usage data from multiple meter points and transmit it to the utility through a wide area network (WAN).

8.3.4 Currents Status of Communication Networks in California

California utilities predominantly favor wireless radio frequency mesh networks as their local-area communications and public wireless networks as their wide-area communications. All of the major utilities are planning to include home area networks (HAN) as part of their AMI/smart grid implementation. The Zigbee™ wireless communications protocol is emerging as the leading standard protocol for HAN-enabled meters and devices.

Table 8-2: Summary of Communications Technologies

	Local Area Networks (LAN)	Wide Area Networks (WAN)	Home Area Networks (HAN)
PG&E	RF Mesh	Common carrier networks and Ethernet	Wireless (Zigbee)
SCE	RF Mesh	Public internet standards-based wireless network	Wireless (Zigbee)
SDG&E	RF Mesh	Public internet standards-based wireless network	Wireless (Zigbee)

Pacific Gas & Electric (PG&E)

AMI: For LAN, PG&E is currently using RF mesh technology provided by Silver Spring Networks. For WAN, Silver Spring Networks is using common carrier networks (CDMA, GSM) and Ethernet.

HAN: PG&E is currently deploying five million Zigbee-enabled meters. It is working with start-ups and big companies to develop in-home display and control devices.

Southern California Edison (SCE)

AMI: SCE is deploying Itron's OpenWay meters and communications system as part of SCE's Edison SmartConnect metering program. OpenWay uses mesh network RF technology for local-area communications and any Internet standards-based network for the wide-area communications. This combination provides a highly scalable and robust network infrastructure. In particular, the Itron design is built so that the "LAN to Cell Relay to WAN" portion of the system can be vendor-agnostic, so that the full functionality of the OpenWay meter can be leveraged across any architecture (Smart Grid News, April 2008[7]).

HAN: SCE is deploying Itron's OpenWay meters that use wireless ZigBee technology to provide real-time communications to energy management devices.

[7] Smart Grid News, April 2008

San Diego Gas & Electric (SDG&E)

AMI: Similar to SCE, SDG&E selected Itron's OpenWay meters and communications system. OpenWay uses mesh network RF technology for local area communications and any Internet standards-based network for the wide-area communications.

HAN: OpenWay meters use Zigbee technology to provide real-time communications to energy management devices.

8.3.5 Key Characteristics of the Technologies

The key characteristics of communication networks are outlined below:

- Throughput: Amount of information followed that can be handled by the communications network. This will determine maximum number of devices, latency of information retrieval, and frequency of polling.
- Coverage: Within an architecture design, the number of points within a given area that can be reached. This will define the number of repeaters or collectors required to operate successfully.
- Obsolescence: The maturity of a given technology and its resilience to changes, also defines the stage of development.
- Reliability: A measure of dependability of a given technology approach to repeatedly and consistently operate at a desired performance level.
- Scalability: Ability to grow functionality (more features); with area expansion (additional points), and ancillary devices (sensors).
- Functionality: Relative indicator of completeness of solution to provide desired outcomes.

8.3.6 Links to Smart Grid

Advanced metering systems are key to extend the vision of the smart grid. They collect data from customer's meters and provide timely information to customers, such as real-time energy price and outage information.

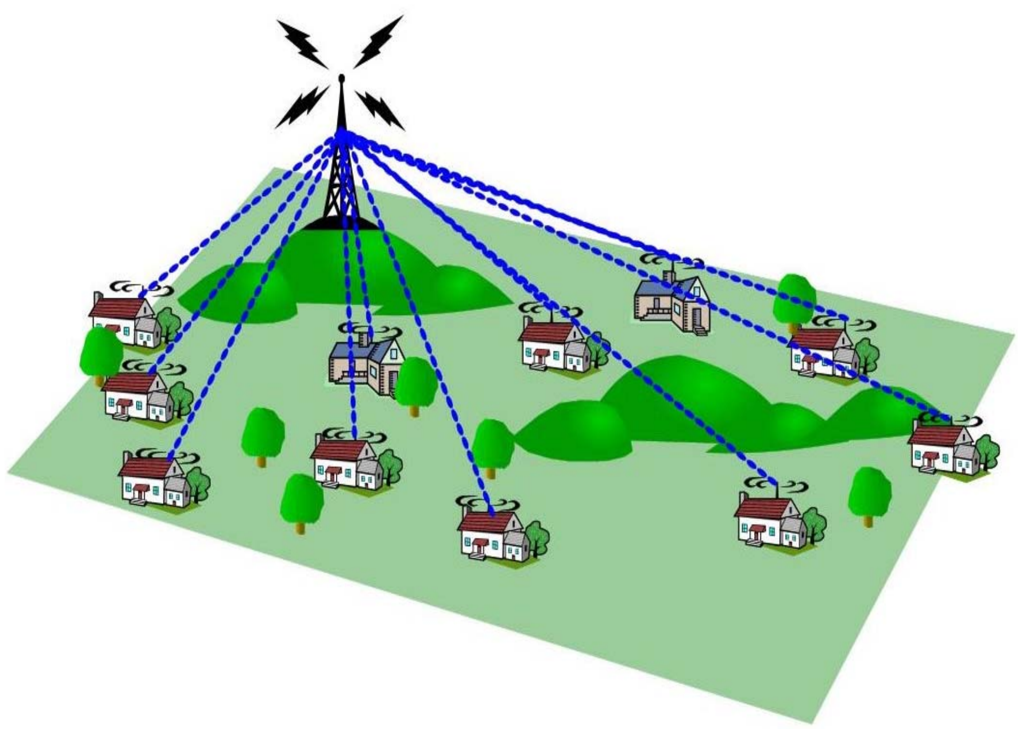
8.3.7 Contribution to Renewable Technologies

These communications networks can extend control and monitoring access to many renewable resources. This allows effective utility distribution network management and dispatch.

8.4 Types of Communication Technologies used for AMI

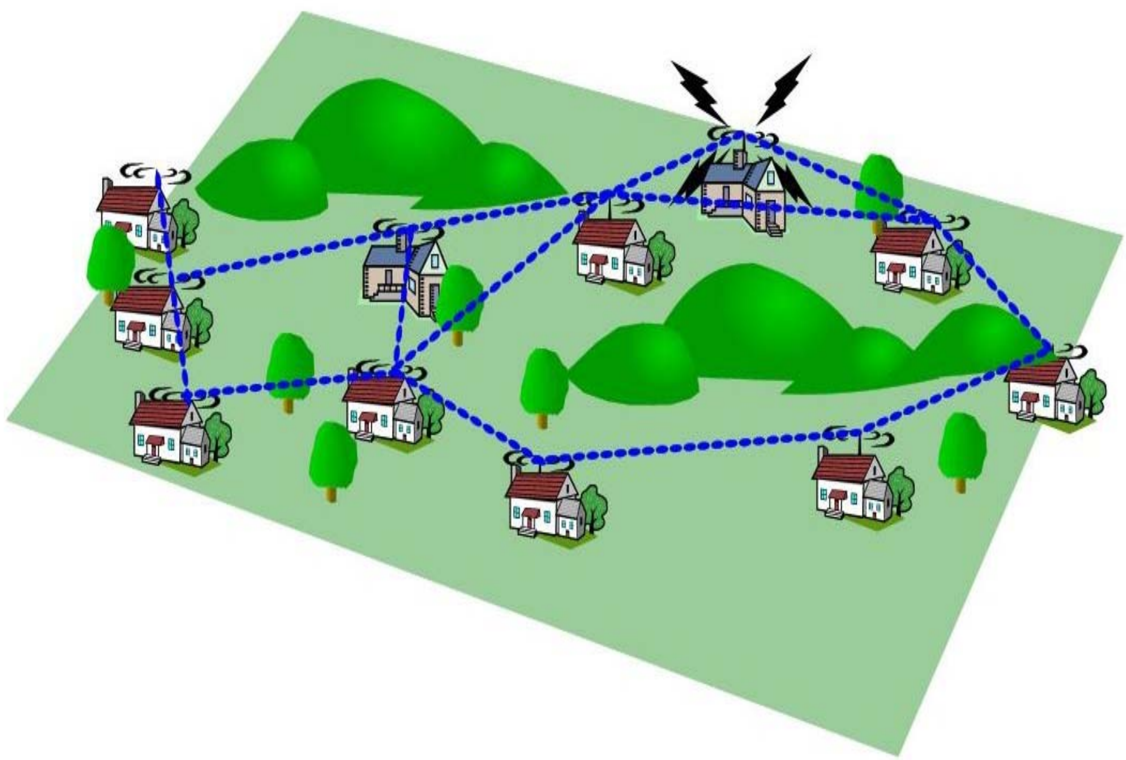
- A **point-to-point (P2P) network** uses an antenna array that provides direct connection to locations. The operating frequencies tend to be lower (450 to 900 Mhz band) and operate at a higher power level through the use of multiple overlapping antennae enabling devices to communicate through different paths. Often different channels are provided so that communications can be optimized. The span of range for a given system can be 10-15 miles and may support hundreds of thousands of end devices. Mesh network is a repeater network where each module repeats or relays the information from other nodes. Figure 8-4 depicts a standard P2P network.

Figure 8-4: Typical Point-to-Point Network



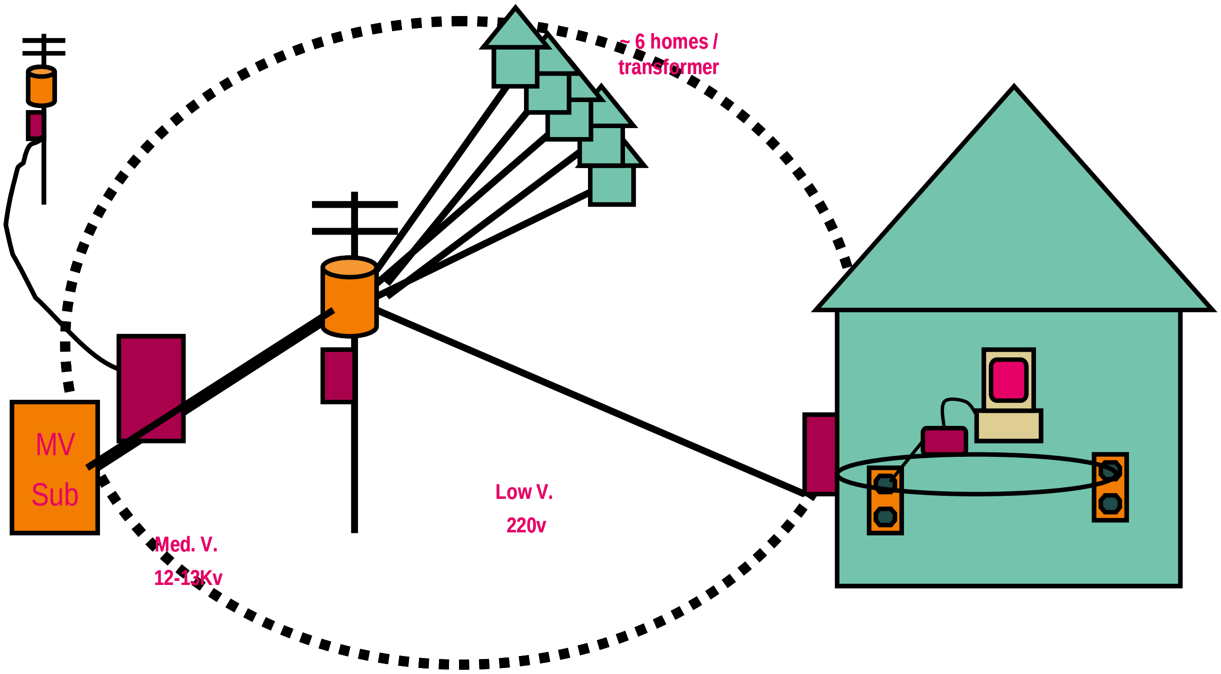
- A **mesh network** relies, at its core, on the deployment of smart devices that have the ability to relay communications from peer units. The elements interact so that a self-configuring and self-healing network forms. A collector or "*take-out*" point is used to link the communications to other elements. The network requires sufficient density to form the mesh; however, this also can be a drawback since congestion and routing need to be managed to ensure adequate throughput. Figure 8-5 illustrates how a mesh network works.

Figure 8-5: A Mesh Network



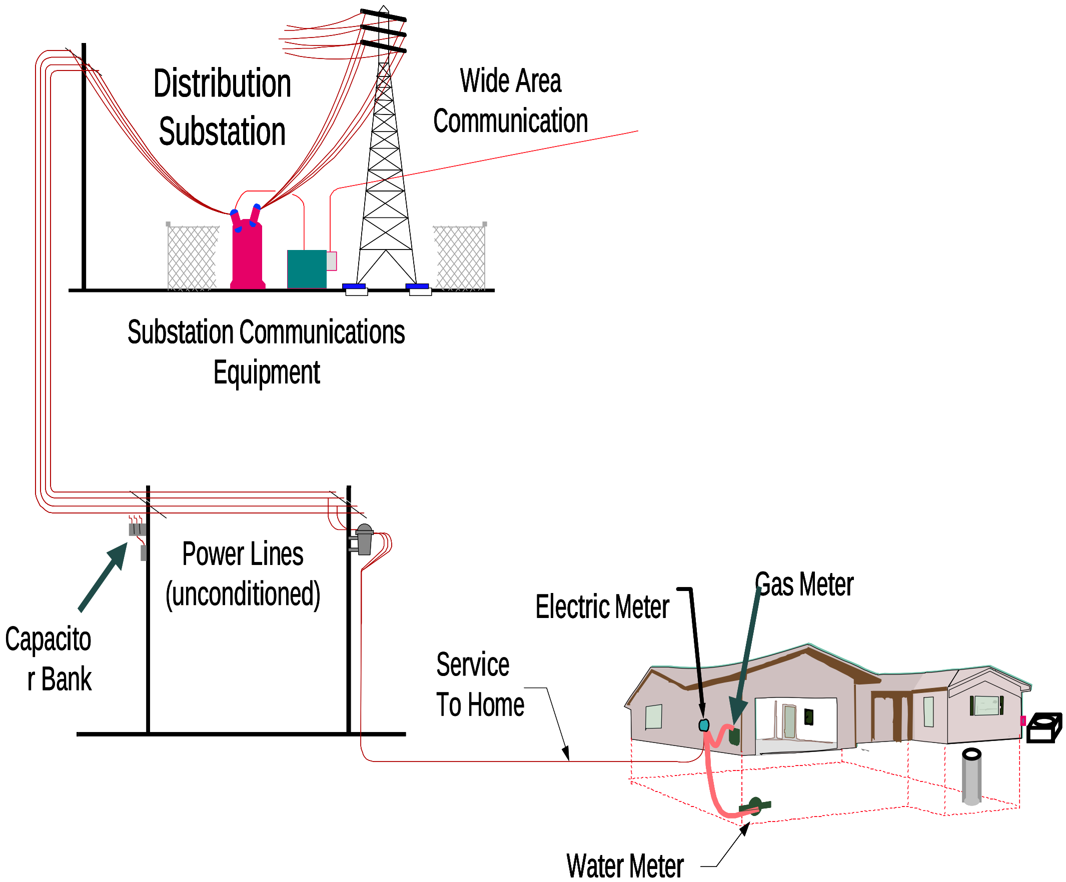
- A **broadband over power line (BPL)** system leverages the existing electrical distribution network to deliver communication service over the exiting powered infrastructure, as shown in Figure 8-6. The use of high frequency signals has distance and interference issues; however, the use of repeaters and bypass devices—to overcome the transformers, switches, and other distribution characteristics—requires significant investment in network components.

Figure 8-6: A Broadband over Power line Network.



- **Medium speed over power line carrier (PLC)** technique uses the existing low-voltage distribution network for communications, as shown in Figure 8-7. One implementation uses a technique whereby the voltage and current waveforms are modulated. In these systems, creating a distortion at the zero crossing allows devices to interact with equipment at the substation without conditioning or bypassing secondary transformers. In other techniques, the wires are used as media for medium frequency transport. These systems require conditioning and bypass of signal blocking elements.

Figure 8-7: Medium Speed over Power line (PLC)



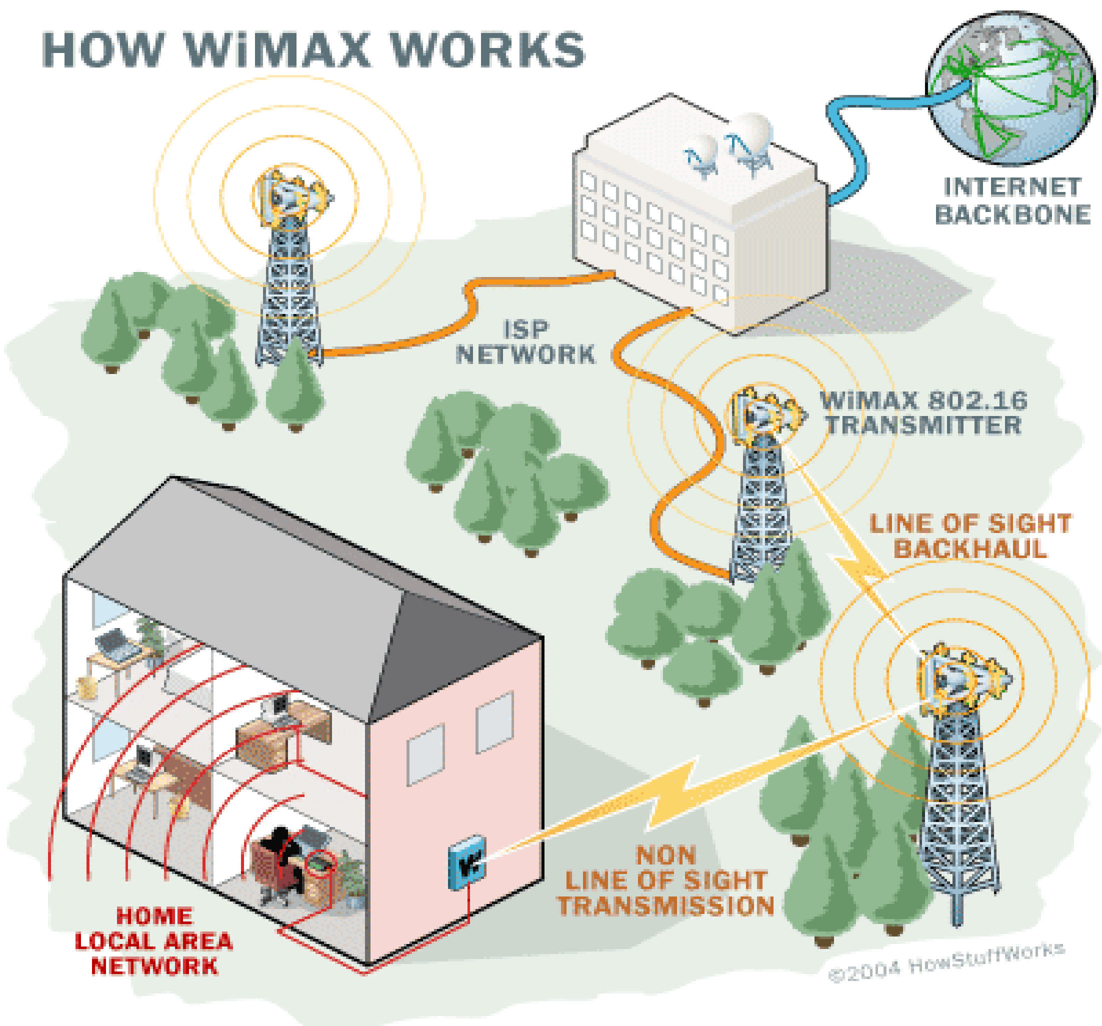
There are two main types of WAN deployment: wireless public carriers or wired. Wireless public carriers can leverage the global system for mobile use; standard wired options include fiber ring or substation delivery.

- **Common carrier wireless WAN**: Wireless voice and data services are currently being provided by major mainstream carriers, such as Verizon, AT&T, T-Mobile, and Sprint. These cellular-based networks are increasing in speed and improving in coverage. Costs continue to decrease as more and more subscribers embrace wireless technologies' access to web services and other information sources. This technology has rapidly evolved and has become a major source of remote access and data mobility.

Another wireless option is common carrier wireless metro area networks (MAN).

- **Common carrier MAN**: There is a growing trend to use wireless data services to bring connectivity to a larger geographic area. Two major offerings in this area include WiFi and WiMax (Figure 8-8). Although the specific characteristics of these technologies vary, they both can offer a relatively wider area of coverage than a LAN.

Figure 8-8: WiMax Network



8.5 Meter Data Management for AMI Systems

AMI systems provide substantial additional meter data, such as daily reporting of sub-hourly interval data from a large volume of customers, and these voluminous inputs must be efficiently and effectively processed, validated, stored, and distributed. MDMs interface with many other utility systems, like customer information system (CIS), asset management, outage management, system planning, etc.

A MDM can also provide the following features:

- Registration and management of the meter inventory in a single system, including interfacing to customer information and asset management systems. Meter inventory management would be consolidated into a single system.
- Interfaces to multiple meter types from different manufactures. Implementation of a MDM with the capability to communicate with multiple meter products and using open standards would preclude lock-in to a single meter product or product line.
- Interfaces to various communications media. As with the capability to support different meter types, flexibility of media interfaces will preclude early obsolescence and facilitate flexibility in the initial implementation and as new functionality is developed.
- VEE (verification, editing and estimating) functionality
- Management of internal meter software, including download of updated software to the meters
- Dissemination of information, including usage data, tamper indications, outage conditions, and other non-consumption related information
- Route optimization functionality.

8.6 Building Automation and Home Automation Systems Technologies with AMI Interface

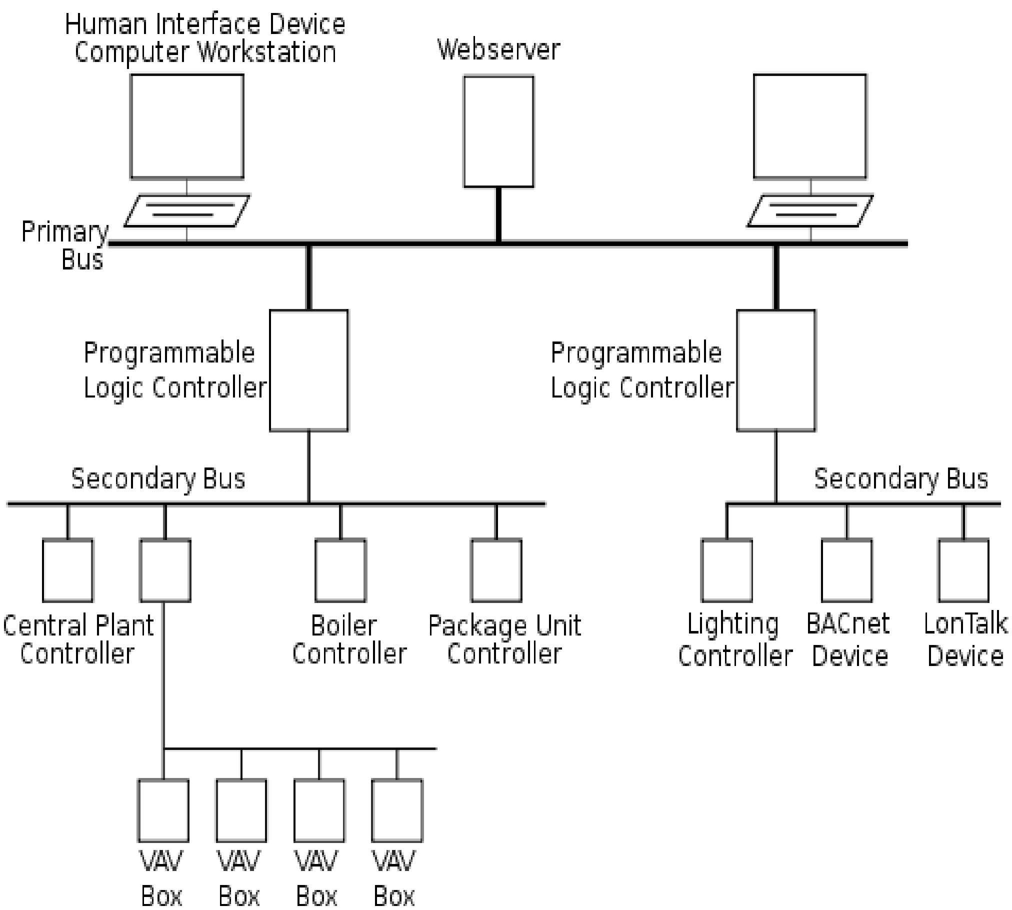
Building automation systems (BAS) and home automation systems (HAS) have been separated into two categories, since there are generally significant differences in each of the application areas. While there are general similarities in each of these systems, the BAS market is more mature, manages a number of conditions within the building, and is primarily installed to optimize occupant comfort and building energy performance. BAS can also include fire and life safety functions.

Although equipment like air conditioning controls (thermostats, programmable and not) and lighting occupancy sensors have been available for years, the HAS market has matured both in the levels of control and intelligence of sensors and control strategies. This market is just beginning to emerge as devices are placed under control and the interaction of external conditions is considered. Integration of distributed generation and smart grid functionality are among the leading factors that are driving the adoption of HAS.

8.6.1 Definition of BAS Technology

The following figure (Figure 8-9) displays a typical BAS.

Figure 8-9: A typical BAS System



The purpose of a BAS is to control the function, duration, and intensity of use for various energy-using systems within a facility. Most large facilities have some type of BAS. The function and level of control of the BAS can vary wildly from facility to facility, as well as the state of calibration and accuracy of BAS controls. Some typical control functions include:

- Lighting Controls:
  - Time of day schedules
  - Daylight harvesting
- HVAC Controls:
  - Time of day schedules
  - Chiller/boiler staging
  - Chilled/hot water supply temperature (including temperature resets)
  - Supply air temperature (including temperature resets)
  - Supply air static pressure
  - Economizer function
  - Area space temperatures.

Each parameter controlled by the BAS is intended to provide necessary functions for the facility (such as comfort) and to optimize energy use.

When integrating BAS function with a smart grid, it is important to draw upon lessons learned from previous initiatives to manage on-site energy use (or peak demand). It is also extremely important to engage customer participation in a manner that will *not* risk the ability to effectively run a business or to safely operate a facility.

8.6.1.1 Automated Demand Response (Auto-DR)

For several years, California has implemented the auto-DR program for a portion of their utility customers. Customers will upgrade their BAS to include a demand response algorithm with the capability to temporarily alter functions of their energy-using equipment to reduce demand during peak periods. A black box is installed at the facility that will accept a signal from the utility to command the BAS to engage the demand response algorithm. The utility will schedule certain days as "*demand response*" days, where they foresee the electric distribution grid having difficulty in maintaining capacity. During these peak times, they will send the Auto-DR "*signal*" to participating facilities. Some typical demand response functions of a BAS are listed below:

- Turn off a portion of the area lighting

- Cycle HVAC units
- Raise space temperature set-points
- Raise HVAC static pressure set-points
- Command variable frequency drive (VFD)-controlled motors to run at slower speeds.

Specific programming strategies are entirely dependent on customer needs and/or goals based on the required operation of their facility. In some cases, customers may upgrade the capabilities of their BAS (add control points for example) to effectively implement demand response strategies.

Other demand response programs exist where customers may implement a demand response algorithm at the request of the utility (not an electric signal from the utility, but through a phone call or e-mail). Also customers may manually turn off or set back equipment without the aid of a BAS algorithm.

The next logical step from Auto-DR would be to implement such BAS strategies with a smart grid. This would offer customers a very powerful tool in controlling their costs should real-time pricing become a reality.

8.6.2 Key Characteristics

Building automation is key to facilitating commercial and industrial (C&I) and small commercial renewable monitoring to the grid. In addition, as hybrid electrical vehicles have the potential to be aggregated at commercial locations, building controls will facilitate managing loads as a tool. For load control and demand response, building control systems will allow better coordination with grid needs, allowing more opportunities for the grid to proactively respond to issues of variable generation from renewables. Additionally, BAS will be useful in helping C&I customers achieve their green building goals.

8.6.3 Links to Smart Grid

The main linkage issue in the future will be integrating information exchanged and managed between BAS and AMI metering. At present, AMI meters have had limited capabilities to interact with BAS. Generally, these meters provide rudimentary consumption information that is used by the BAS and building manager. However, as smarter meters equipped with more robust information make their way into the marketplace, the intersection of metering and BAS will become more strategic and valuable. This is particularly evident as smart grid and distributed energy resources become more predominant. A key factor to this drive will be the effective use of net metering as buildings potentially can become energy sources for the grid.

8.6.4 Contributions to Renewable Energy

BAS and intelligent building control (IBC) are essential elements to enable renewable energy. The ability to interact with external conditions and to effectively manage the grid-to-building (G2B) and building-to-grid (B2G) will occur through and in concert with these technologies.

8.6.5 Communications for Commercial Building Automation Systems

Interoperability protocols are used to govern communications within a BAS. Some protocol developers place the standard in the public domain for use of any vendor, such as Honeywell, Siemens, or Johnson Controls, in developing equipment for the BAS. Some protocol developers choose to keep portions of the protocol proprietary while allowing manufacturers to develop products that adhere to the standards set by the protocol. The most widely used protocols today are BACnet, Modbus, N2, and LonWorks.

- **BACNet**: Building automation and control network (BACnet) is the term commonly used to refer to the ANSI/ASHRAE Standard 135-1995, adopted and supported by the American National Standards Institute (ANSI) and the American Society of Heating, Refrigeration, and Air-Conditioning Engineers (ASHRAE). BACnet is a true, non-proprietary open protocol communication standard conceived by a consortium of building management, system users, and manufacturers. The BACnet protocol defines a number of services that are used to communicate between building devices. The protocol services include Who-Is, I-Am, Who-Has, I-Have, which are used for device and object discovery. Services such as Read-Property and Write-Property are used for data sharing.

- **Modbus**: Modbus is an open protocol, meaning that it is free for manufacturers to build into their equipment without having to pay royalties. It has become a very common protocol used widely by many manufacturers throughout many industries. Modbus is typically used to transmit signals from instrumentation and control devices back to a main controller or data gathering system.

  Modbus is a communication protocol developed by Modicon systems. In simple terms, it is a way of sending information between electronic devices. The device requesting information is called the Modbus master and the devices supplying information are

Modbus slaves. In a standard Modbus network, there is one master and up to 247 slaves, each with a unique slave address from 1 to 247. The master can also write information to the slaves.

- **N2:** Is the BAS protocol developed by Johnson Control that is used between network control units (NCUs) and the individual equipment or central plant controllers. The N2 protocol was widely accepted in integration by a number of external fire alarm, security, chiller, boiler, lighting, variable frequency drive, and leak detection manufacturers. Johnson Controls allows external manufacturers access to their N2 protocol to continually add new products to be integrated into their control scheme. Several legacy BAS systems can also be integrated into the N2 protocol to allow control operation and integration between two formerly proprietary systems.

- **LonWorks:** LonWorks is a networking platform developed by Echelon Corporation that supports interconnection of various devices operating over a variety of media, such as twisted pair, telephone, powerline, and fiber optics. The communications protocol (LonTalk) is an accepted standard for control networking (ANSI/CEA-709.1-B). This control networking protocol has expanded beyond BAS and is now used in applications such as in-train controls, including electro-pneumatic braking systems for freight trains. The Lon protocol is also one of several data link/physical layers of the BACnet ANSI/ASHRAE standard for building automation. Among the key features supported in LonWorks is both the ability to operate peer-to-peer as well in a hierarchy.

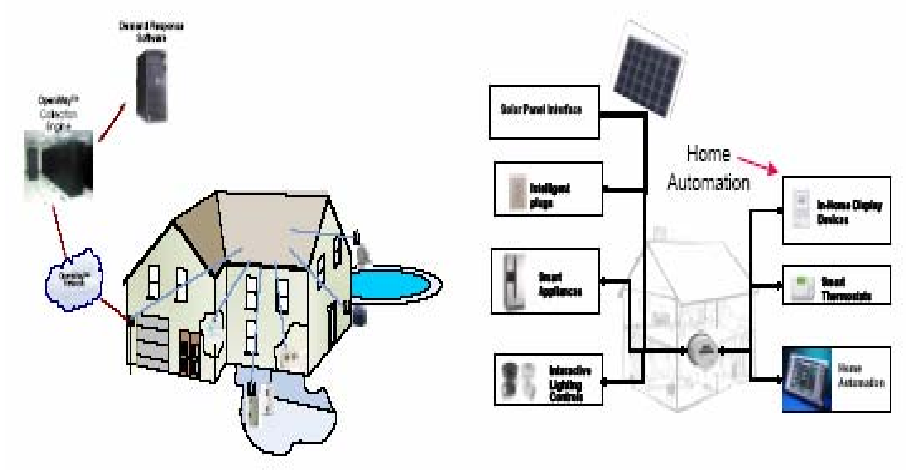
8.6.6 Examples of BAS Technology and Applications

Today, the main application of BAS in smart grid applications is to enable demand response (DR). There is limited penetration by utilities into building automation systems as a service for their clients. Generally these systems are locally installed, managed, and operated. They are sometimes connected to utilities; often this interface interacts with DR (the auto-DR program in California). Current applications of large solar PV installations and their metering by PMRS/PDP are an extension of building automation technology. Most of the PMRS-supplied metering systems use open protocol of ModBus to gather metering data and various alarms of solar sensors in their data loggers, then transmit those to the PMRS/PDP servers. Because many of the building controls use the same protocol, integration with the building automation is easier through PMRS-supplied systems.

8.7 Home Area Network Technologies used with AMI

The following figure (Figure 8-10) displays a common configuration for a home area network (HAN) system.

Figure 8-10: Home Area Network



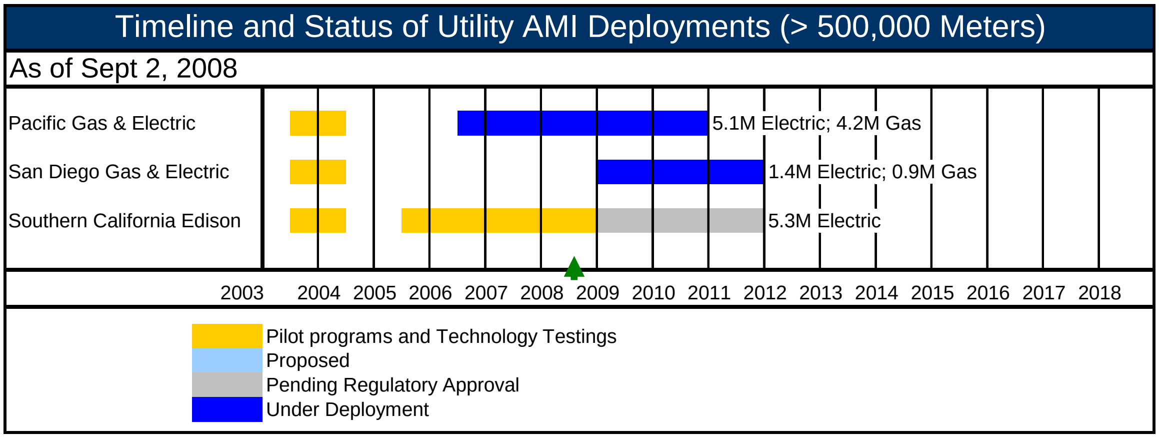
8.7.1 Definition of HAN Technology

HAN is an extension of smart grid or AMI technologies into customers' homes. It transmits data between a utility smart meter and home energy devices through a communications gateway. With HAN, utilities and customers can potentially manage load by remotely controlling home devices, such as programmable and communicating thermostats, load control units, in-home display devices, and distributed energy resources.

8.7.2 Current Status of HANs in California

These systems are often grouped with AMI efforts that are being implemented in the State of California. Each of the main utilities is implementing smart grid-level programs around advanced meters. A summary of these activities from the three largest utilities in California is shown in Figure 8-11.

Figure 8-11: Summary of California AMI Efforts



8.7.2.1 Southern California Edison

SCE is engaged in a seven year, $1.3 billion exercise commencing in 2009 to install electricity meters throughout southern California (except Los Angeles), serving 13 million people and 5.3 million meters.

- Currently selecting AMI infrastructure solution, but have specified ZigBee for every meter, and have also selected cellular for backhaul
- Have selected Itron OpenWay for communication backbone
- Looking for non-Itron meter to use Open Way to maintain open approach
- Have selected HAN/Local ZigBee platform, since they maintain best fit with requirements
- Considered 6loPAN but there are predictions that it will not be ready for deployment in 2009.

8.7.2.2 Pacific Gas & Electric

In a program extending from 2007 through 2012, PG&E plans to install 5.1 million electricity and 4.2 million gas meters at an approximate cost of $1.74 billion (approx $157 per meter). The proposed meters are wireless for gas and PLC for electricity.

- Using communication infrastructures including Star Hexagram fixed-wireless network
- The Hexagram solution uses licensed power (450-470MHz) radio contained within ‘blot on’ modules. This also looks to be a one-way AMR Solution

- Network includes an AMI interface/MDM function between meters and utility systems.

8.7.2.3 San Diego Gas & Electric

By 2011, SDG&E will install 1.4 million new electricity meters with 900,000 AMI-enabled gas modules.

8.7.3 Key Characteristics

The implementation of a HAN can be broadly categorized into either a wired or wireless network.

- Wireless Network: The major wireless communications standards are Zigbee, Z-Wave, and Bluetooth. They are mesh networks based on radio frequencies. These networks have low data rates (usually 250 kilobytes per second (kbps) or less), consume little power, are extremely inexpensive, and can reliably control hundreds of devices in performing quick simple tasks. The range of a wireless network is around 150 feet for Zigbee and Z-wave, and between 10 to 100 meters for Bluetooth.
- Wired Network: Wired networks take advantage of existing wiring, such as power lines, Ethernet cable, coaxial cable, and phone lines for communications. It is inexpensive, has a wide range, and can reliably control hundreds of devices within a fraction of a second.
- Hybrid Network: A hybrid approach complements the characteristics of both a wired network with a wireless network. A wireless network is limited by its range, while a wired network is limited to devices that connect to the household power line system. By having both networks, customers can ensure seamless home area communications.

8.7.3.1 Links to Smart Grids

A HAN is usually deployed with utilities' AMI implementations and are considered components of the AMI roll-out.

8.7.3.2 Contribution to Renewables in California

HAN technologies may become key enablers for renewables like PV. In particular, they can provide a means to connect information from various elements such as inverters and storage devices. The emergence of interoperable standards will foster this enabling capability.

8.7.3.3 Types of Applications

Today, the main application of a HAN is to enable demand response. Many utilities, such as Centerpoint, SCE, PG&E, SDG&E, Consumers Energy, and Oncor, are deploying AMI combined with HANs. A HAN allows utilities to communicate to various energy devices at the customer's site during a load reduction event. The utilities can automatically trigger load reduction on HAN-enabled equipment, based on the customer's predefined settings. In addition, customers can manually adjust on-site load based on information (e.g., real-time pricing) communicated to them from the utilities via displays on their HAN devices. As smart grid needs grow, a HAN can provide a cost effective way to gather meter data from solar PV generation, since this information (e.g., EPBB-type smaller kW sites) is currently too costly to obtain.

8.8 PMRS/PDP Service Offerings and AMI Service Offerings (comparison)

Table 8-3: A Comparison of PMRS/PDP vs. AMI Service Offerings

Business Driver for Solar Meters and Data Collection	Comments	PMRS/PDP collecting data and transmitting to Administrator	Utility System AMI collecting data
Payment for solar generation incentive under EPBB	Meters generally provided are required to be more than 5% accurate. Most of the smaller systems do not have monitoring systems.	This service is generally not bought if cost for PMRS/PDP service is higher than 1% of the installed cost for residential solar system. One time payment is made by utility.	Utility may need this data in future. If utility wants to gather this data for future use, it may need to install meter to communicate with the location net meter.

Business Driver for Solar Meters and Data Collection	Comments	PMRS/PDP collecting data and transmitting to Administrator	Utility System AMI collecting data
Payment for solar generation incentive under PBI	Meter systems' accuracy must be better than 2%. Interval data (minimum 15 minute) readings are required. Service is required for receiving solar performance-based incentives for five years. What happens after five years?	PMRS/PDP acquires the 15-minute data from the data logger and accumulates it in a server. Customer can display this data by logging into the PMRS/PDP web site. Once a month, every 15-minute interval generation from solar system is transmitted to administrator (Utility).	Utility takes the net meter data to the MDM system. Data received from PMRS/PDP is not in the same format as AMI meters. Even if this data is integrated with the other AMI meters, customer has to buy this service from PMRS/PDP after five-year mandatory period has expired. Utility calculates the payment and sends this to the owner/owner's representative based on date received from PMRS/PDP.
Customer Disconnect	Meter can have a remote operated switch for residential applications.	There is no need for solar meters to include remote disconnect.	Net meter for residential systems may be fitted with remotely operated switches.
Web-monitoring service	Monitors generated energy and demand for every 15 minutes; data logging and alarming; hosting service; weather information, carbon reduction information; and solar-string level monitoring to decrease the downtime and increase production.	PMRS/PDP provides near real-time display of performance of solar system accessible from anywhere to the owners of the solar system.	Utilities are trying to provide higher level of current information through web access, but it will take time to provide this level of customization. Generally data for weather and sun at each location will not be available.
	Smaller systems (EPBB systems) most likely will not purchase the data transmitting service and will not receive this information. For larger systems, customers are not obligated to share the energy generation information with utilities after five years.	Most PMRS/PDP services provide a very wide array of solar performance-related information, including emails of uptime for additional cost. Other information – weather station, battery charging, etc. – is available in easily understood dashboard type screens.	Utility AMI system can provide web monitoring services for energy. At this stage, there is no plan to offer all the specialized web monitoring services regarding solar equipment monitoring to the customers.

Business Driver for Solar Meters and Data Collection	Comments	PMRS/PDP collecting data and transmitting to Administrator	Utility System AMI collecting data
Data Security and Validation		PMRS/PDP suppliers provide this service.	MDM in AMI is generally programmed to provide this service.
CPUC data requests for program monitoring	Provide data to CPUC or its vendors for measuring program effectiveness. Payments provided, solar generation installed for the systems.	PMRS/PDP has to fill in the data requests for each of the administrators for CPUC needs. Smaller systems, which are not monitored, will have to be poled by others.	If solar generation data is collected through AMI, it will be able to meet any request from the CPUC if meter is installed for smaller systems. Then all data requests can be provided from this system. Currently, utilities are administering the request but are asking PMRS/PDPs to provide the data.
Net Metering / Billing, Time of Use (TOU), Critical Peak Pricing (CPP)	Providing billing for net energy used and implementing demand management strategies by providing timely price level to consumers.	PMRS/PDP are not involved in this service.	Utility AMI will be a major tool to provide these services by using HAN devices.

8.8.1 Analysis of Service Overlaps, Cost and Impact of using AMI on PMRS/PDP Market

Utilities in California are installing the net meter and, once AMI is fully functional, will be reading the data through their communication network. At the same time, the PMRS is installing its meter for solar generation (for PBI cases) and receiving data through broadband internet supplied by the customer. Data received by the PMRS is sent to the administrator (two out of three administrators are the same utility companies that installed the net meter) for incentive payments to the owner. Data communication from the owner's premises to the utility collection system is much cheaper due to the scale of deployment in comparison to the cost of setting up cellular or broadband connection used by the PMRS. As listed in Section 1.7, PMRS provides other services to the owners, which AMI systems are not currently set up to provide and may never be able to specialize for placement in the solar marketplace.

Table 8-4: PMRS/PDP versus AMI

Item	PMRS/PDP	AMI in California
Accuracy for Meter–EPBB	<5% for the system	<0.25%
Accuracy for Meter includes CTs, wires–PBI	<2% meters have 0.2% accuracy	<0.25%
Data Transfer Communication	Broad band (DSL), Ethernet, Land Line, Cell phone	PLC carrier and RF Mesh
Voltage	120V, 208V, 240V, 277 / 480V	120V, 208V, 240V, 277 / 480V
Data Logger	Some kind of data logger is used to collect data from electronic meters. Most of the systems use current transformers (CT) even for residential-sized systems.	Meters are generally self contained including communication cards. For higher capacity CTs may be required.
Communication between Meters, Solar Controllers Weather Stations	ModBus	Zigbee (wireless) is most likely being planned to be used between meters and HAN devices at the same location. If AMI is used to collect data from solar meters, it will most likely use a Zigbee device to send data through net meters, which are connected to AMI infrastructure.
Overlaps of Resources	- Meter Reading–remote - Responding to PUC inquiries - Data management - Web management - Metering system trouble shooting	- Meter Reading–first manually or drive-by, but eventually through remote AMI. - Responding to CPUC inquiries - Data management - Web management - Metering system trouble shooting
Where PMRS and AMI do not overlap	There is no metering testing requirement for the solar meters after installation as payments (PBI) are only made for five years.	Utilities have to prove accuracy of metering to CPUC through testing (generally through statistically valid sampling techniques).

Table 8-5: PMRS/PDP versus AMI Cost Comparison

	PMRS/PDP		AMI	
	Cost in Dollars	Comments	Cost in Dollars	Comments
Residential Service				
Meter and hardware	\$300 - \$500[1]	Not many PMRSs in this business of offering residential systems	\$60 - \$100 \$250 \$400[2]	Does not include cost of meter box Changed to two socket box
Installation	\$500 - \$1,200[1]		\$33 - \$45 \$200 - \$300	Meter alone Meter box installation by contractor
Annual monitoring and back office service	\$35 - \$350[1]	Customer provides the communication, e.g., internet connection	\$60 - \$100[2]	
Meter and hardware	\$3,000 - \$15,000	Depends upon the options offered. Weather station, Pyranometer, string level sensors	\$300 to \$500 \$1,000 - \$2,000[2]	Does not include CT, PTS CTs, PTs in the customer's switchgear for installation
Installation	\$1,000 - \$2,000		\$1,000 - \$2,000[2] (Note 2)	
Annual monitoring and back office service	\$150 - \$1,000		\$60 - \$100[2]	

General Note – We have estimated some of the cost numbers for the interim report. By the time the final report is submitted we will have confirmed cost numbers to report.

[1] This cost is estimated. Generally, most of the smaller residential systems exceed the cost cap (1 percent) of the installed system and receive exception to the monitoring requirements. Some systems may use the inverter meters as a proxy, cost may be lower than the cap, and may be monitored by PMRS.

[2] Generally, AMI costs are provided for retrofitting existing metering installations. New installations of AMI meters for solar systems will require a meter box for residential and CTs and PTs for commercial or large solar applications. This cost is estimated.

Note Overall cost of a PMRS/PDP system is used for comparison – hardware + hardware installation (generally by others) + servers + web interface + data collection labor + monthly data transmittal labor cost to utility + administration of PBI payment + customer support + warranty cost + testing cost + program administration, including responding to CPUC inquiries profit. Prices in above table reflect what PMRS are charging to their customers.

AMI system cost – Hardware + hardware installation + incremental cost for data transfer (usually not much as net meter is already being monitored as part of tariff) + incremental cost of data gathering (MDM) + data processing cost + customer support + PBI payment administration + program administration, including responding to CPUC inquiries.

Figure 8-12: Average AMI Meter Cost

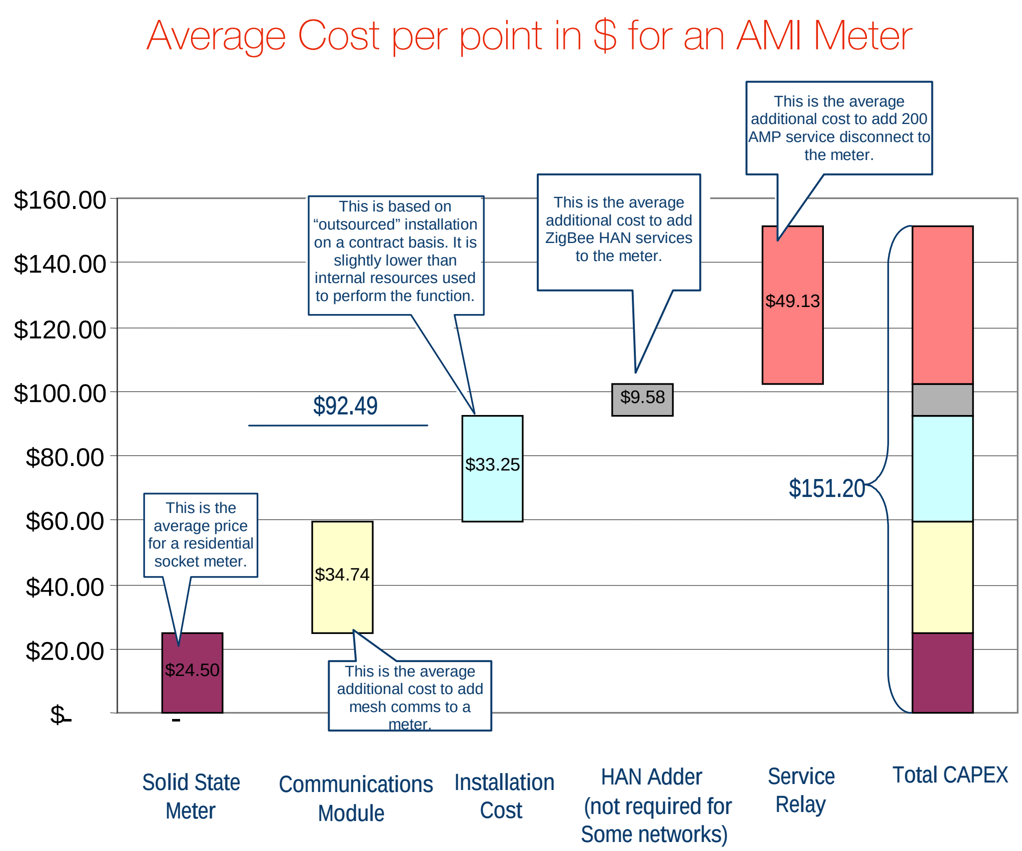


Figure 8-13: Large AMI Cost

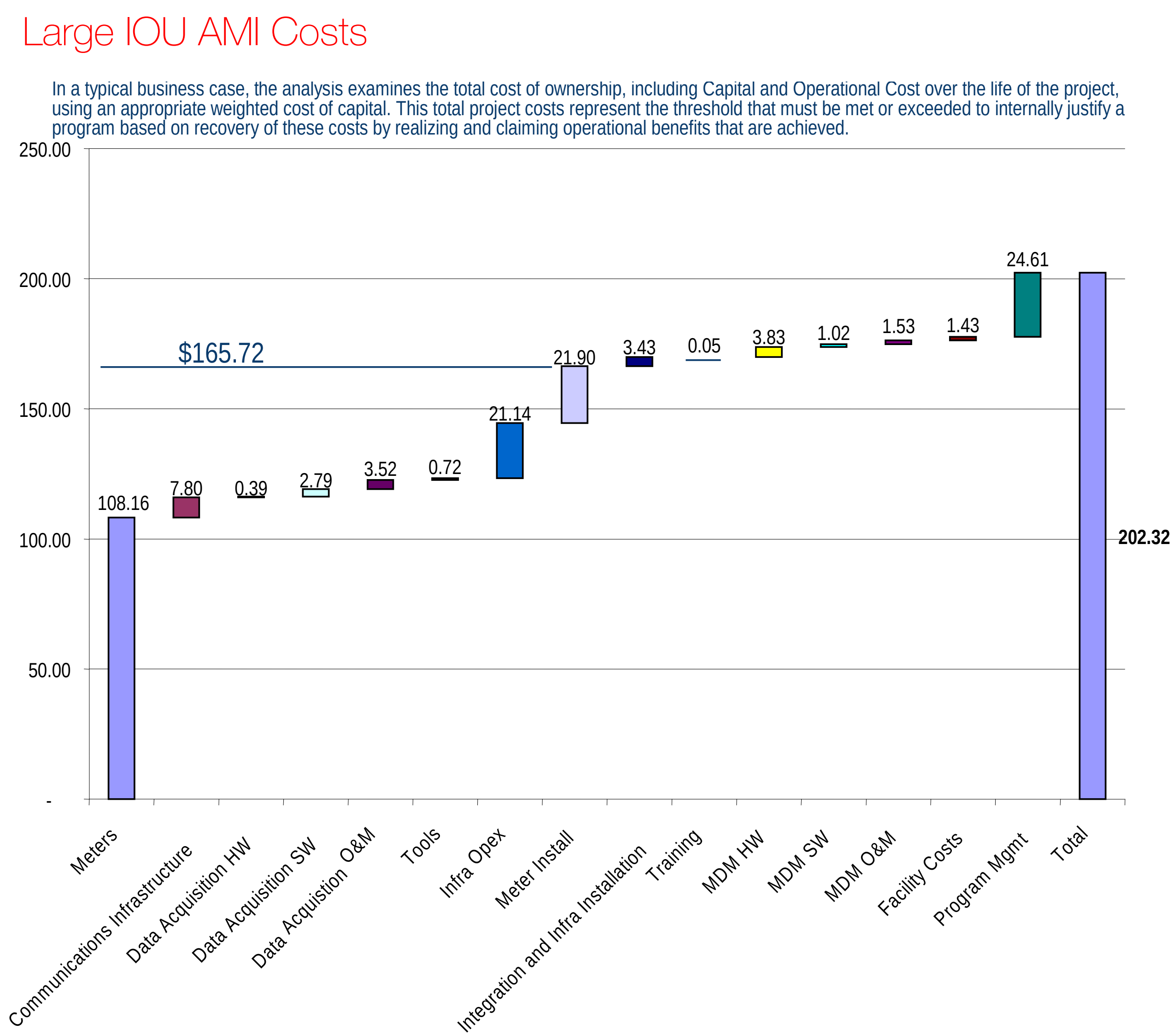


Figure 8-14: Cost Descriptions

Cost Descriptions

Meters	Solid state meters with integrated communications module appropriate to the technology selected.
Communication Infrastructure	The hardware associated with building a meter to collector local area network. This would include the installation of this system as well.
Data Acquisition hardware (HW)	This is the communication aggregation hardware that would collect information from all remote devices, typically a server.
Data Acquisition software(SW)	This is the vendor supplied software that supports the information gathering and formatting prior to it being sent to a Meter Data Management (MDM) system.
Data Acquisition O&M	These are the recurring costs associated with the information aggregation system; generally it is a recurring software maintenance and hardware refresh over the life of the project.
Tools	These are supporting tools that are required for the installation commissioning and ongoing support of the AMI network.
Infra Opex	These are the recurring fees associated with the communications network; this would include any regular network fees paid to common carriers.
Meter Install	This is the cost associated with the labor to install a meter.
Integration and Infra Installation	This is the cost associated with the testing and commissioning the Infrastructure; costs would include any fees that may have to be paid to mount hardware on non-utility assets.
Training	These are the vendor costs associated with information transition and education on the system and infrastructure. It would also include training on the MDM system.
MDM HW	This is the cost of the various servers, communications processors and other computing equipment associated with the MDM system. This would also include any technology refresh costs over the life of the project.
MDM SW	These are the software license costs associated with the core and required applications to support the MDM.
MDM Integration	These are the systems integration costs required to link the MDM to the existing utility back office.
MDM O&M	These are the on-going costs of operating and maintaining the MDM system; this would include any recurring maintenance support fees.
Facility Costs	These would be any costs associated with adding facilities during the installation phase of a program. Incoming meters and outgoing meters would be housed here and would be dispatched to respective work out centers. This would also include computer systems and other support infrastructure for the staff associated with the program.
Program Labor	This is the incremental labor force required for the program. Included are a PMO, technology staff, support organizations, logistics, troubleshooting and all support areas.

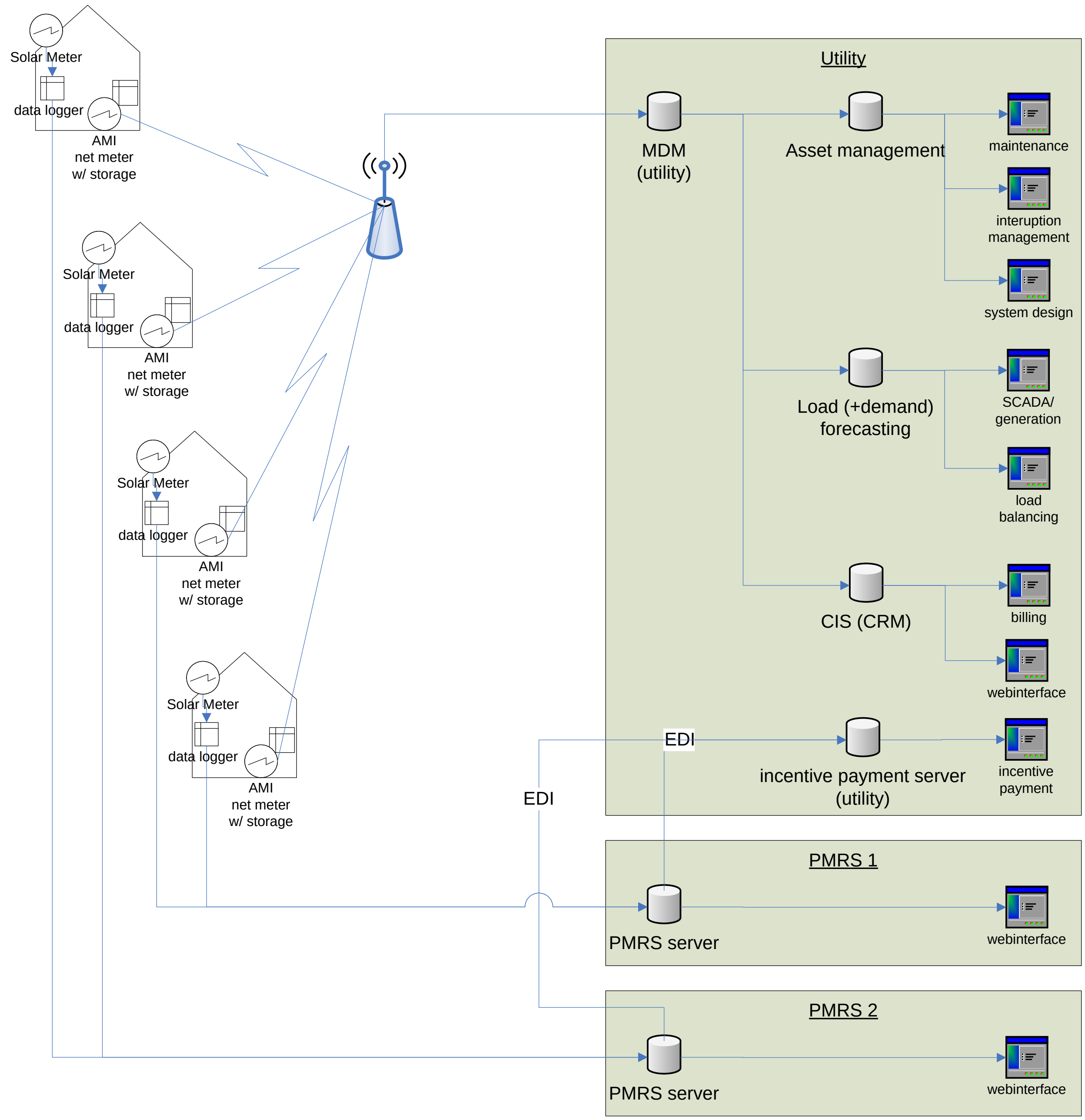
8.9 AMI Integration Options

At present, California utilities are not integrating data from solar meters into the AMI MDMs, as most of the data collected from larger solar systems through PMRS/PDP are required to pay incentives under state PBI requirements. Integration of the solar data with normal consumption data has many benefits (see Section 1.1.2) and may cost more for that information than currently being planned. There are three options of integration of this data:

- Current system with no integration—Collects all usage data through net meters via AMI and collect data from PMRS/PDP for PBI payments. Manually integrates data whenever needed.
- Integrates the data collected from PMRS/PDPs for PBI into AMI MDM and prepares plans to buy data from PMRS/PDP after five years when mandatory period expires. Add AMI system meters to un-metered solar generators whenever data is required.
- Add AMI meters at the source, i.e., home or commercial site, for all solar generators and integrate data from the premise to the MDM, CIS, and other systems.

8.9.1 Current Configuration of AMI and PMRS/PDP Services

Figure 8-15: Current AMI and PMRS data collection



Most California utilities are in process of installing smart meters and communication structures to gather interval usage data. When solar systems are installed at a location, solar generation information is either not gathered (except for an EPBB payment) or is gathered through a 15-minute interval meter and is transmitted through the PMRS/PDP communication structure to the utility for incentive payment. Utilities have not integrated solar generation data into their meter data base. By mid-year 2009, all PDPs will be transmitting PBI data through EDI once a month, but this data will be only used for paying incentives.

SCE is collecting data from various PMRS/PDP in their own servers. PG&E and CCSE (working on behalf of SDG&E) are outsourcing the data collection through EDI. We have provided a sample of EDI data in Appendix D.

Generally, AMI data streams will be similar, but most likely will have meter reads at each of the 15-minute intervals. Net meters at the location will communicate through LAN communications (RF mesh) means to the MDM system and transmit 15-minute interval reads. MDM generally will provide the information to the systems, like CIS, for billing and customer web interface, load forecasting, interruption management, asset management, and so forth. AMI is an integral part of long-term smart grid strategy.

Using these assumptions, Table 8-6 highlights pros and cons of AMI versus PMRS data collection for solar systems.

Table 8-6: AMI and PMRS Data Collection Pros and Cons

PROS	CONS
Simple – Keeps PMRS/PDP data separate from AMI. Assumes that only significant generation from solar systems will be from larger systems and will not add serious issues to distribution planning and operation, dispatching, and customer service.	Smaller solar systems are not monitored remotely and can not be accessed. Manual integration of data from PBI-required solar systems is possible. Two data collections are separate and serve different functions, but data received by utilities can be used for some of the engineering and operational purposes. As data is transmitted once a month, real-time information to utility will not be available.
Fewer meters (only for PBI program) to monitor and record. Keeps cost low.	After five years, some of the larger solar system may not renew the monitoring service and as CSI does not require data transmission to utility—utility may not even know about the solar system generation at any given time, even for the larger solar systems.

PROS	CONS
	After a few years of numerous solar system installations, record keeping for solar generation may be cumbersome without some kind of monitoring.
	If data is needed in future by the utilities, complications and cost of collecting data through EDI by three utilities through three different methods may be higher compared to collecting through AMI systems.
	As all solar systems are not monitored, higher cost of getting additional information for program evaluations for CPUC.[1]
	In case some of the PMRS/PDP businesses fail, data from those sources will become an issue. After five years for PBI-type customers, utility may have to make some arrangement to continue receiving this data.

[1] Overall cost comparison of metering using PMRS/PDP plus program administration versus AMI data for all solar meters plus program administration (which may be quite different) is not in the scope of this analysis, but it may lead to different conclusions.

8.9.2 Integration at Utility Level

One way to integrate AMI and PMRS/PDP services is to collect data from PMRS/PDP and transmit it to the utility server using EDI. With further manipulation, data can then be sent to the MDM or other utility systems, as shown in Figure 8-16. Data from PMRS/PDP may be in meter-read form and require reporting frequency greater than once per month. PMRS/PDP may need to provide meter data to the utility for ad-hoc meter polling. Merging data from two systems (PMRS/PDP and AMI) and transmitting that data to MDM may create unwanted problems without providing sufficient benefits.

Figure 8-16: Data integrated at MDM level

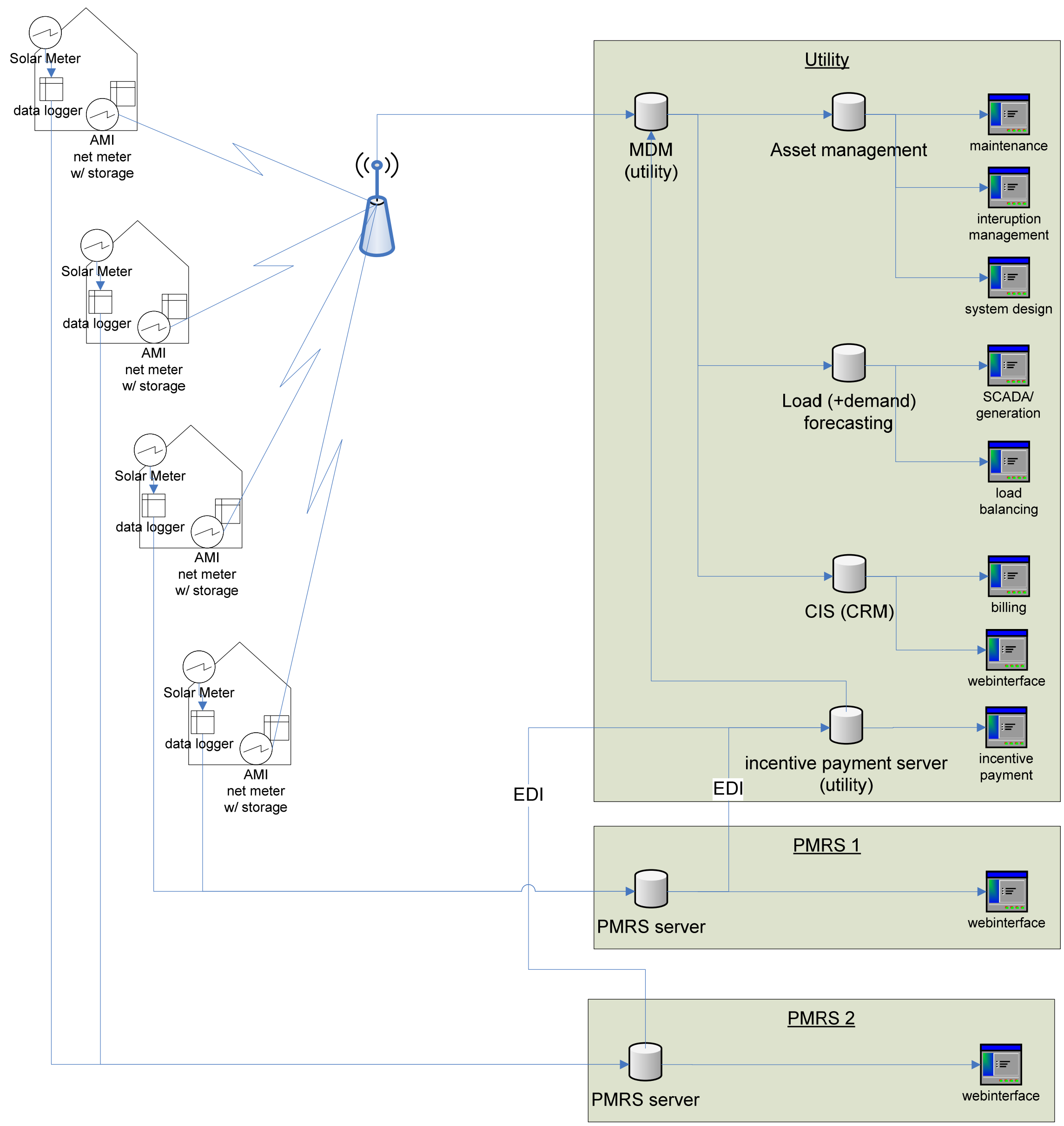


Table 8-7 highlights the pros and cons of data integration with MDM.

Table 8-7: MDM Data Integration

PROS	CONS
Data is integrated at MDM/CIS level for larger solar systems.	Smaller systems are not remotely monitored and cannot be accessed by the utility. Some additional programming and processes are required to integrate the PMRS-supplied data with the utility AMI data. Data from PMRS will still be available only once per month and will not provide any ad-hoc meter inquiries.
Fewer meters to monitor and record, which keeps costs low by not monitoring smaller solar installations.	After five years, some of the larger solar systems may not renew the monitoring service thus interrupting data flow to the utility.
Cost and Flexibility: Utility will have option to add meters for solar systems that are not presently being monitored without losing data for those systems where interval meters already exist.	After several years of solar system installations, record keeping for solar generation will be difficult without some type of monitoring system.
No new meters will be needed by utilities for systems already being monitored by PMRS.	Working with two systems will be burdensome for utilities. The benefits of receiving 15-minute data will not be obtained with monthly file transfers. Ad-hoc meter polling by utilities will not be possible.
	PMRSs are not obligated to provide data after five years, forcing the utility to make other arrangements to capture solar generation data.
	Integration of data from many organizations and at different times during the month is complicated. Data validation, reporting of non-performing meters, and ad-hoc data collection further compounds the problem.
	If PMRS businesses fail, data from those sources will be lost. For those businesses that remain after the required five-year collection period, utilities will need to make special arrangements to continue receiving data.

8.9.3 Integration at Source Level

To integrate source-level data, the solar meter must be capable of transmitting that data to the utility's communication infrastructure and may, in fact, have to be the same type as the net meter. If a communication link can be established, the utility can integrate the data with back office systems, provide updates on how much generation is provided by the solar PV to the CPUC on a regular basis, and use the information to further implement smart grid initiatives. The ideal integration method is to enable the AMI system to communicate with solar meters (inverter or a separate meter) regardless of who installed them. To meet this objective, standards must be developed requiring that solar meters include ZigBee capabilities so that solar data can be passed to the net meter and transmitted to the utility as required.

Ideally, meters used by solar systems (PBI) should be compatible or similar to those used by the utilities so that future data needs will not require major retrofits. To keep solar system costs low, inverter meters should be standardized to communicate with both PMRS and utility net meters. Figure 8-17 illustrates how this integration would work.

Figure 8-17: Data integration at source level

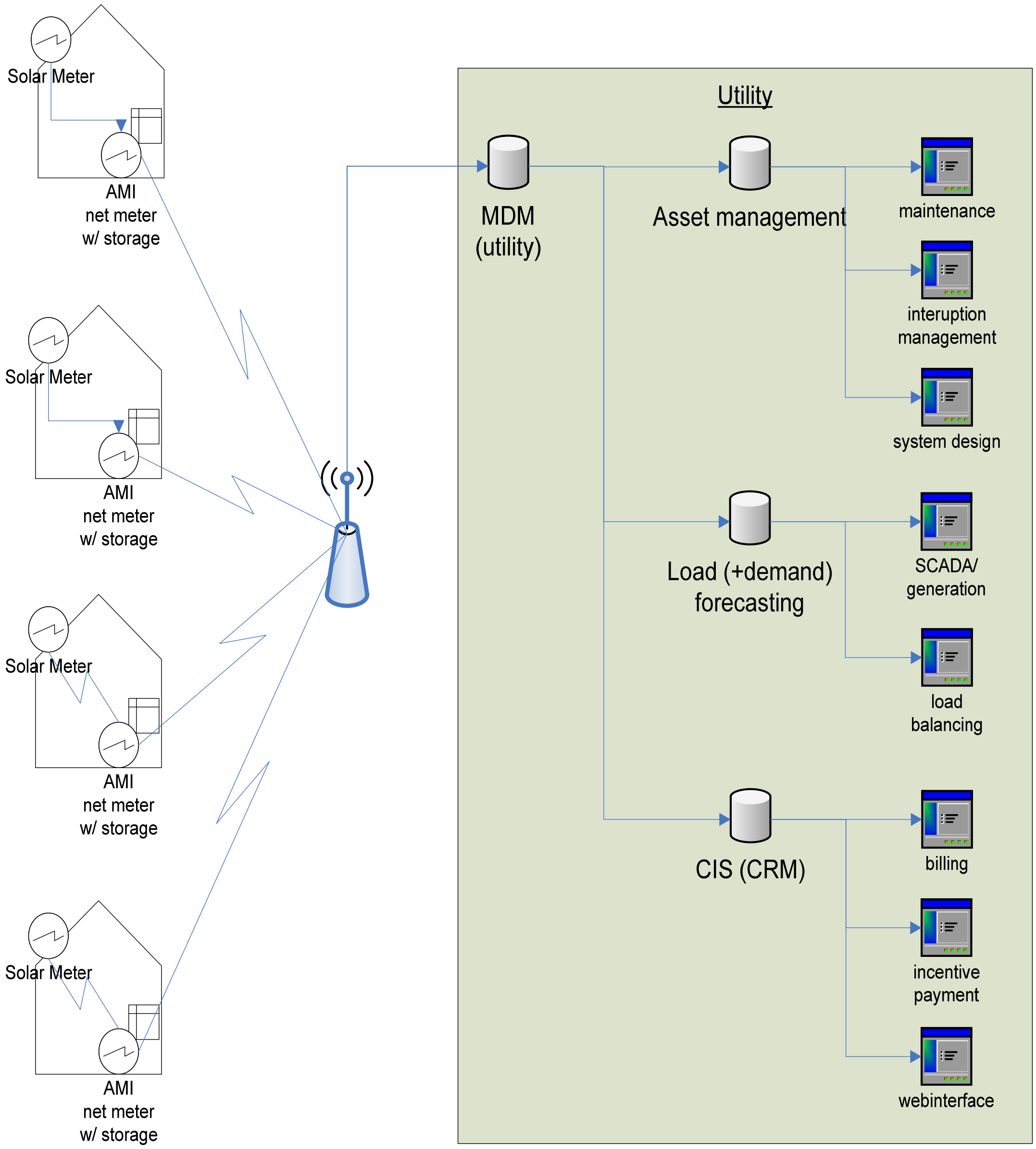


Table 8-8: Pros and Cons of Source-level Integration

PROS	CONS
Simple integration – one system.	Smaller systems are not remotely monitored and cannot be accessed by the utility.
Utilities are in the business of monitoring and providing metering service.	This model may limit the use of PMRS service.
If smaller solar systems must be monitored in the future, a system to integrate them will exist. Smart grid vision can be implemented in stages.	Utility-owned metering cannot provide real-time solar system performance using a web browser and may not be able to provide real- time maintenance alarms through emails.
Utilities can account for RECs, reduce costs by using their existing AMI system, and achieve economies of scale.	If utilities install meters for smaller solar systems, costs for smaller residential system will increase.
Aligns with smart grid vision.	

8.10 AMI Integration and the Impact on PMRS/PDP

A utility AMI system is designed to serve a large number of customers and monitor their energy needs, while PMRS/PDP systems provide many additional benefits, by providing analysis such as solar system degradation and system failure notification. Large solar system owners may wish to pay more to receive additional services, but smaller system owners (EPBB-level or even some PBI) may not see value in these advanced analysis capabilities, especially once the five-year mandatory monitoring period expires.

There are many data collecting requirements for solar installations (as discussed in the earlier sections) and standards specifying that all meters (whether installed by PMRS or utility) are able to communicate (using Zigbee standard) with AMI at the premise level are required. One financial benefit that must be addressed is the trading of RECs. Smaller solar systems may have to install revenue-class meters and provide those readings to receive any benefits. The cost for metering and monitoring systems to serve this objective must be low; therefore, utilities may be able to provide a service that captures RECs from smaller solar generators currently receiving exceptions from monitoring due to cost caps.

There are close to 40 PMRS/PDP companies competing for solar system performance and energy-monitoring contracts with only six as the main players in this new industry. Some of the

PMRS/PDP suppliers may have other revenue sources or may be expanding in other geographic areas, but many are focused on this type of business. As other states provide more incentives for solar or alternative energy installations, PMRS/PDP businesses will grow and become stable and prosperous businesses. This industry is in its infancy and will likely experience consolidation before a few key players emerge. PMRS/PDP companies are developing many innovative services and technologies using the Internet, which may cease if competition emerges from AMI technology.

8.11 Final Comments and Recommendations

AMI technologies—designed for large scale deployment—measure energy consumption, improve outage management, and provide higher customer service. PMRS services are designed to provide value by improving the operational efficiencies of solar generation and improve asset return on investments. PMRS services are purchased by the owners of solar generation to receive the CSI incentives. These customers also receive other solar system monitoring services. AMI and PMRS overlap in collecting energy data at the same location satisfying two different objectives: net metering measures the net energy (AMI) delivered to or received from the customer site; solar metering measures the energy generated by the solar system.   If AMI is used for metering and monitoring of solar generation, it can provide the following benefits:

- Accounting for the financial benefits of RECs from smaller solar systems, which are currently not being monitored due to exceeding the cost cap. Larger systems using revenue-class meters for solar generation will be able to sell their RECs through PMRSs.
- Streamlining program management and reporting, and reducing costs, if all solar generations are monitored and data is consolidated using the utility's AMI meter data management system.
- Realizing the vision for a smart grid.

A PMRS provides many other services that improve the performance of solar systems, including web monitoring. Since AMI costs are lower for basic services, PMRS businesses will suffer if utilities provide these metering and monitoring services to solar generation owners. For larger systems, utilities receive data once a month only for the first five years from a PMRS/PDP. If they need solar data beyond this period, additional arrangements must be secured.

It will take several years to implement AMI systems throughout California. To fully realize the benefits that these systems can provide, KEMA offers the following recommendations:

1. All solar installations should have revenue-class accuracy meters to measure solar generation and receive potential RECs' credit. Overall metering system accuracy (including current transformers, voltage transformers and wiring) should be equal to or better than 2%.

2. All solar meters (including the inverter meters if used) should provide data in a format that is compatible with AMI meters (15-minute interval data) currently used by the regional utility, including ZigBee interface (either installed or with provisions to install). All solar meters need to follow open standards, so that a utility can integrate all solar systems into their smart-grid vision.

3. Utility/solar program administrators should have options to capture data, as needed or on a continuous basis, to provide measurement and evaluation of solar systems.

These changes to the CSI Handbook will make solar systems AMI-ready and not inhibit PMRS services to solar owners.

9. Section G – Compare Metering Requirements to Other Renewable Energy Incentive Programs

Numerous utilities and energy providers across the U.S. and the globe have implemented renewable energy incentive programs to increase PV usage within their customer base. Using the CSI Program as a baseline, this section discusses 15 of these programs and their metering requirements.

9.1 The California Solar Initiative

The CSI has a $2,167 million budget over 10 years with the goal to reach 1,940 MW of installed solar capacity by 2016. The CSI program distributes incentives via an up-front lump sum payment based on system capacity (EPBB), as well as a five-year incentive based on actual system output (PBI). It is the intent of the program to ensure optimal value for both solar owners and ratepayers; therefore, it is important for CSI to have accurate solar energy output measurements and monitoring. For solar electric generating systems receiving an EPBB incentive, a basic meter with accuracy of ±5 percent is required; for systems receiving PBI payments, an interval data meter with accuracy of ±2 percent is required. A PMRS is required for EPBB systems if the PMRS is below a certain cost cap (1 percent of systems <30 kW and 0.5 percent for systems >30 kW). For PBI systems, both PMRS and PDP are required regardless of system size and cost.

California requires all utilities to offer net metering to all customers with solar systems up to 1 MW. Net metering is a favorable billing policy that allows solar customers to reduce their electric bill with their solar generation. CSI customers can apply for net metering after their solar system is installed and approved by their local building authority. The utilities will then send an inspector on site to do a final inspection and install a bi-directional net energy meter. The bi-directional meter must be accessible to utility workers for readings and maintenance. Depending on the customers' original rate schedule, they may be asked to pay the utility a fee to cover the labor and hardware expenditures.

In the January 2007 decision D.07-01-018, the CPUC concluded that renewable distributed generation facility owners should retain 100 percent of the RECs associated with their facilities, irrespective of participation in net-energy metering or the CSI. This decision allows California solar system owners to sell their RECs to RPS-obligated load-serving entities for extra incentives. However, the CPUC has not yet finalized a decision on integrating RECs into the flexible RPS compliance system; therefore, a RECs' compliance market does not currently exist in California. When a REC market comes into play in the future, then the solar RECs are expected to be accounted by the WREGIS for RPS compliance. WREGIS currently requires a metering accuracy of within 2 percent, which is more stringent than what the CSI requires for its EPBB systems. WREGIS is currently reviewing this rule.

9.2 Objective and Methodology

The objective of this section is to compare and contrast metering requirements of solar energy incentive programs to the CSI. KEMA considered 15 PV incentive programs in the U.S. and around the world. For each program, KEMA conducted a review of all publicly available information, including information gathered from the Database of State Incentives for Renewable Energy (DSIRE) and from the websites of these programs. When possible, KEMA interviewed program staff to confirm and obtain additional information. We have provided a copy of the market research survey as Appendix F and a list of program staff interviewed by KEMA during this research as Appendix G.

Since a program's incentive structure, customer's access to net metering, and the treatment of RECs are factors that could affect metering requirements, it is important to investigate a variety of solar incentive programs that have different combinations of these factors. The table below lists the programs KEMA investigated in the research:

Table 9-1: PV Programs Considered

	Incentive Structure Availability		RECs owner-ship	Net-metering	Research Methodology	
	Capacity-Based	Performance -based			Internet	Interview
California Solar Initiative (CSI) - California	< 100kW	All	PV owner	✓		
City of Palo Alto Utilities PV Partners Program (CPAU) - California	< 100kW	All	PV owner	✓	✓	
Sacramento Municipal Utility District (SMUD) Solar Incentive - California	< 1 MW	All	utility	✓	✓	✓
City of Roseville Solar Electric Rebate Program (Roseville)- California	All		utility	✓	✓	✓
Los Angeles Department of Water and Power Solar Incentive Program (LADWP) - California	All		utility	✓	✓	✓

	Incentive Structure Availability		RECs owner-ship	Net-metering	Research Methodology	
	Capacity-Based	Performance-based			Internet	Interview
Burbank Water and Power Solar Support Rebate (Burbank) - California	< 30 kW	All	N/A	✓	✓	
Glendale Water and Power Solar Solutions Program (Glendale) - California	< 30 kW	All	N/A	✓	✓	✓
NV Energy Generations Rebate Program (NV Energy) - Nevada	All		utility	✓	✓	✓
Public Service New Mexico (PNM) Solar PV Program – New Mexico		All	utility	✓	✓	✓
Arizona Public Service Solar Incentive Program (APS) - Arizona	All	All	utility	On-grid systems only	✓	✓
New Jersey Renewable Energy Incentive Program (New Jersey) - New Jersey	< 50 kW	Voluntary RECs trading	PV owner	✓	✓	✓
New York State Energy Research and Development Authority (NYSERDA) Solar Electric Incentive Program - New York	All		State	✓	✓	✓
Massachusetts Technology Collaborative Commonwealth Solar (MTC) – Massachusetts	All	Voluntary RECs trading	PV owner	✓	✓	
Gainesville Regional Utilities Residential Solar Rebate Program and Solar Feed-in Tariff (GRU) - Florida	Residential Customers	Commercial customers	Utility	Residential customers	✓	✓
Solar Bonus Scheme - Queensland, Australia		All	PV owner	✓	✓	
Feed-in Tariffs “Einspeisevergütung” (Germany) - Germany		All	Utility		✓	

9.3 Summary of Findings

Metering requirements vary from program to program depending on system size, system accessibility, and treatment of RECs, but vary mostly by incentive structure. There are two types of metering that are relevant to these solar incentive programs: net metering and performance metering.

Net metering. Most states require their utilities to offer net metering to customers with distributed generation systems such as solar PV systems. For net metering, utilities generally use a bi-directional meter, one that allows electricity to flow in both directions—forwards to measure electricity consumption and backwards to measure electricity production. For customers who opt for time-of-use rate: the generation during on-peak hours is credited against the customer's consumption during on-peak hours; and the off-peak generation is credited against the customer's off-peak consumption. This arrangement is deemed advantageous to solar customers who generate more than they consume during the peak hours.

The net meter is always utility-revenue grade, usually meaning it complies not only with third-party testing, but that it has been tried, tested, and verified by the utility. In the U.S., third-party testing generally means that it is certified by the ANSI, in this case, specifically standard ANSI C12.1. ANSI C12.1 is the overall equipment performance standard for electricity-revenue meters. It includes the performance and influence specifications for electromechanical meters as well as specifications common to all ANSI meters, such as reference conditions, design acceptance test procedures, surge withstand tests, insulation tests, environmental tests, and mechanical tests.

When a customer applies for net metering, the utility usually goes on site to switch out their original billing meter and install a bi-directional meter. CPAU is one of the few utilities investigated that gives bi-directional meters to all customers; and therefore, does not require the customers to change their meters when they switch to net metering. These meters are generally read along the utility's monthly meter reading route. Utilities, including LADWP, Glendale, and ones in New York, are implementing AMI and are in the process of replacing traditional net billing meters with ones that have remote communications capabilities.

Performance metering. Most solar incentive programs require performance metering. Some program administrators (usually utilities[8]) pay for, install, and maintain the performance meter and its associated communications system; some customers are required to contribute to the

[8] SMUD, Roseville, LADWP (for systems larger than 10 kW only), Glendale, NV Energy, PNM and Gainesville.

meter base.[9] For Germany's feed-in tariff, the grid operator is responsible for the performance metering. The rest of the utilities studied require their customers to pay for their own metering as part of the total solar system cost. In these scenarios, the program might specify meter location, equipment eligibility, and minimum warranty. Most commonly, utilities require customers to locate the performance meter adjacent to the utility billing meter. When there are equipment restrictions, the CEC-eligible equipment list is the most frequently cited list.

Of the 15 programs investigated, 10 are performance-based incentive programs or have a performance-based incentive component (not including net-metering benefits). The performance-based component is required for customers with large systems (such as the programs run by some of California's publicly owned utilities); required for all commercial customers irrespective of size (like Gainesville's solar feed-in tariff); or in the form of voluntary RECs trading[10]. Like the CSI, programs that provide performance-based incentives have more rigorous metering requirements than capacity-based incentive programs. Specific performance metering requirements vary vastly from program to program, and quite frequently within the same program. Utilities or program administrators might require the metering equipment to come with a minimum warranty of 1 year to 10 years.[11]

The table below summarizes the key performance meter requirements for performance-based incentive programs.

Table 9-2: Performance Metering in Performance-based Incentive Programs

Program	Incentive Type	Accuracy	Data Frequency	Storage	Communications
CSI	PBI	2%	15 minutes	See Note 1	Remote communication to PMRS/PDP
CPAU	PBI	2%	15 minutes	5 years	Port capable of enabling remote performance monitoring
SMUD	PBI	0.2% -	N/A	N/A	N/A

[9] NV Energy and PNM

[10] When RECs are assigned to PV customers and a RECs market exist, PV customers could sell the RECs at a dollar per kilowatt hour rate for additional incentives.

[11] LADWP, MTC and CPAU specifically require metering equipment to be warranted for 1, 2, and 5 years respectively. Burbank generally states that all equipment must be warranted for 10 years.

Program	Incentive Type	Accuracy	Data Frequency	Storage	Communications
		0.5%			
Burbank	PBI	2%	15 minutes	N/A	N/A
Glendale	PBI	0.5%	N/A	N/A	Most are read manually; remote and new systems are radio-enabled for reading up to 500 feet away from a handheld device.
PNM	PBI	1%	N/A	N/A	Read manually
APS	PBI	3%	N/A	N/A	Dedicated phone line
New Jersey	RECs	> 50 kW: 1% 10-50 kW: 5% < 10 kW: None	N/A	N/A	> 50 kW: automatic monthly reporting via electronic exchange 10-50 kW: monthly data self reporting < 10 kW: No reporting required.
MTC	RECs	N/A	N/A	N/A	> 10 kW: automatic monthly reporting 10 kW or less: voluntary self-reporting via web.
GRU	FIT	2%	N/A	N/A	Small systems: read manually Large systems: read remotely via wireless phone line
Germany	FIT	N/A	N/A	N/A	Read manually

Note 1: Meter must store the system's lifetime production data and its interval data for 7 or 60 days depending on daily or monthly reporting

N/A: Information not available.

Of the 15 programs investigated, 12 of them are capacity-based incentive programs or have capacity-based incentive components. These programs are usually limited to smaller systems, for example, Burbank, Glendale, CPAU, and SMUD, limit the system size to 30kW, 30kW, 100 kW, and 1 MW respectively. These programs generally have fewer metering requirements than performance-based programs. Meter accuracy is more lenient, for example, requiring ±5 percent instead of ±2 percent, and inverter-integrated meters are sometimes acceptable in lieu of dedicated meters. Since the incentives are not tied to performance, some programs[12] simply require that meter displays are assessable to customers for self-monitoring. GRU is the only program investigated that does not specify any metering requirements.

Some utilities with capacity-based program, like Roseville, SMUD, and NV Energy, install relatively sophisticated performance metering for their customers at their own expense, so that they could accurately account for the RECs generated for their RPS-compliance. In New Jersey's and MTC's capacity-based incentive programs, customers might comply with stricter performance metering standards in order to participate in the solar RECs market.

The following table summarizes some of the performance metering requirements in capacity-based incentive programs.

Table 9-3: Performance Metering in Capacity-based Incentive Programs

Program	Accuracy	Dedicated meter	Other requirements
CSI	5%	Inverter-integrated acceptable	Meter display for customers; need to retain data during outages
CPAU	5%	Inverter-integrated acceptable	Meter display for customers
SMUD	0.50%	Yes	
Roseville	> 10 kW: 2% < 10kW: 5%	Yes	Designated phone line to communicate with large systems
LADWP	5%	Yes	Need to retain data during outages
Burbank	Not Specified	Inverter-integrated acceptable	N/A
Glendale	0.5%	Yes	Most are read manually: remote and new systems are radio-enabled for reading up to 500 feet away from a handheld device.
NV Energy	2%	Yes	Lifelong recording
APS	3%	Yes	Adjacent to existing utility meter

12 CPAU and MTC.

Program	Accuracy	Dedicated meter	Other requirements
New Jersey	10-50 kW: 5% < 10 kW: None	Yes	10-50 kW: monthly data self reporting < 10 kW: engineering estimates
NYSERDA	5%	Metering display acceptable	The energy metering data must be automatically stored independently of the inverter display.
MTC	N/A	Yes	Meter display for customers: > 10 kW: automatic monthly reporting 10 kW or less: voluntary self-reporting via PTS
GRU	None	N/A	N/A

The following sections give detailed descriptions of each program's incentive structure and how it relates to the program's metering requirements.

9.3.1 City of Palo Alto Utilities' PV Partners Program

CPAU offers a capacity-based rebate for systems under 100 kW. For systems 100 kW and above, the rebate is paid over a five-year period based on measured system energy production (kilowatt-hours). The PBI is fixed for each applicant over the entire five-year term. In addition, systems 100 kW and above are eligible to sell solar RECs directly to CPAU at $0.05 per kWh. The RECs payment is made over the five-year term of the performance-based incentive.

All solar customers are net metered. CPAU does not change the customer's electric billing meter when PV is installed, because the existing analog meter is bi-directional.

Performance meters are required by the PV Partners Program for all rebated solar systems. All meters measure and display output in kW and kWh, retain production data during power outages, and have a communication port capable of enabling remote performance monitoring and reporting service. For systems less than 100 kW, production meters are required to have a ±5 percent accuracy. This requirement can be fulfilled by inverters with ±5 percent metering displays.

For systems over 100 kW using the PBI, meters must be revenue-grade and have ±2 percent accuracy. The meters must be tested to all applicable ANSI C12 testing protocols and have interval data recording (15 minutes or less). The system seller or installer must retain and provide the system owner and CPAU with remote access to 15-minute average data for a minimum of five years. A remote performance monitoring and reporting service is also required. Monthly system energy production data must be reported to CPAU in a specified electronic format for calculation of the performance-based incentive and for REC payment if applicable. The PDP may be the system owner, seller, or a designated third party. All program participants must provide access to the PV production meter for testing, inspection, or data collection. Installers are encouraged to locate PV production meters in an easily accessible area.

9.3.2 Sacramento Municipal Utility District Solar Incentive Program

SMUD offers cash incentives to commercial, industrial, and non-profit customers who install solar PV systems. Customers have the option of taking a one-time, up-front payment through the Expected Performance-Based Incentive (EPBI) or payments over the course of a five-year or ten-year period through the PBI. The expected system performance is calculated by PowerClerk and considers factors such as components used, system orientation, and shading. Customers who install systems under the PBI will have their actual energy production measured during the course of the contract period. Options include a five-year PBI at \$0.30/kWh or a t10-year PBI at \$0.18/kWh. Systems greater than 1 MW are only eligible for the five-year or ten-year PBI (at lower incentive rates) under a third-party power purchase arrangement. Upwards of 80 percent of SMUD's customers choose the EPBI scheme to help cover the upfront cost of installing a PV system.

SMUD installs two revenue-grade utility meters on all systems. The first is a bi-directional meter that is used as a service meter and read during meter reading routes. The second is a generation meter that keeps track of total PV system generation. For systems under the EPBI, the second meter is used to determine REC generation. For PBI systems, this meter is also used to determine the incentive payment in addition to the REC generation. All single phase meters installed by SMUD have an accuracy standard of ±0.5 percent and all three phase meters adhere to a ±0.2 percent accuracy standard.

9.3.3 City of Roseville Solar Electric Rebate Program

Roseville Electric's Solar Electric Rebate Program offers solar rebates at \$3.00 per AC watt, with a maximum rebate of \$10,000 for residential customers and \$66,000 for non-residential customers. All systems are equipped with two meters, one for net metering and one for performance metering and REC generation. The net meters are ANSI-certified, utility-grade, bi-directional meters of ±2 percent accuracy installed for billing purposes.

Roseville requires systems of 10 kW or smaller to install a CSI-eligible performance meter of ±5 percent accuracy. Systems above 10 kW are installed with meters of ±2 percent accuracy. Roseville is able to communicate with the meters installed on the larger systems via a designated phone line that Roseville installs, pays for, and maintains. In the past, Roseville has used wireless communication, but found it troublesome due to unreliable access. Customers can access the performance data that Roseville collects through an online account service provided by *Square D*.

9.3.4 Los Angeles Department of Water and Power Solar Incentive Program

LADWP's Solar Incentive Program pays rebates for PV systems on an expected-performance basis, similar to CSI's EPBB program. LADWP uses the PVWatts calculator to estimate expected kWh produced, based on system size, system design, and certain performance assumptions.[13] Since the rebate is based on expected performance instead of actual performance, it is considered a "capacity-based" program for the purpose of this study.

All customers are required to install a separate performance meter that reads the total system's electricity production and is at least ±5 percent accurate. The meter must be listed with the CEC. The meter must retain the kWh production data in the event of a power outage and must provide a display of system output that the customer and LADWP can easily view and understand. The meter must be rated for outdoor use and be installed outdoors in close proximity to the LADWP billing meter. Residential installations require a separate four-pin meter socket with an electromechanical meter having either an analog or liquid crystal display. The meter must be independent of the inverter in case the inverter is replaced, removed, reprogrammed, or loses its date. Specific meter requirements for small and large systems differ.

Small systems in LADWP are defined as systems that are 10 kW or smaller. The performance meter must be paid for by the solar customer. LADWP allows refurbished or used meters; program staff estimates meters cost around $15- $20 each. Since these are mechanical meters with no communication capabilities, the meters must be manually read. As of March 2009, LADWP did not read these meters or monitor the performance of small PV systems. Currently,

[13] LADWP assumes PV systems have a 20-year life and a 0.9 percent degradation of performance annually.

there are no plans to read these meters; however, if RECs from distributed generation come into play in the future, LADWP will include the reading of solar performance meters in their regular meter reading routes.

LADWP pays for,[14] tests, and installs performance meters on large PV systems, defined as systems greater than 10 kW. The performance meters are AMR meters that have the capability to communicate remotely via RF and satellite. Currently, the AMR meters used are Elster A3 and Ladis+Gyr AxR S4; however, LADWP is in the process of replacing all AMR meters to Elster meters. These meters record data every 15 minutes and store all historical data. LADWP actively monitors 12-16 of their large systems each month (about 15 percent) and is able to detect when a system is having problems (e.g., when a fuse is blown). Performance data is also available to PV customers via “MVWeb,” where customers are able to see their systems’ performance information.

9.3.5 Burbank Water and Power Solar Support Rebate Program

For systems equal to or below 30 kW, Burbank provides a two-tier solar incentive program that pays a $3.00/watt base incentive for all customers and an enhanced $3.50/watt incentive for customers who assign their system’s RECs to the City of Burbank. Solar systems greater than 30 kW receive incentives paid out over the first five years of the system’s life on a per kWh basis.

All solar customers have two meters—a net meter and a performance meter. Burbank installs a bi-directional net meter before the system is connected to the grid at no cost to the customer. Performance meters are required for all systems rebated in Burbank’s Solar Support Rebate. Meters and service panels must meet all local building and utility codes. In addition, Burbank is a member of the Electric Utility Service Equipment Requirements Committee, and all service equipment must comply with the applicable committee guidelines and drawings.

Systems equal to or smaller than 30 kW can use an inverter’s built-in performance metering display in lieu of a separate performance meter, or install a performance meter at the customer’s option and expense. Burbank accepts meters that are listed at the CEC website.

[14] Staff estimates the cost of each meter is about $240 each.

Systems larger than 30 kW AC are required to purchase a performance or generation meter with ± 2 percent accuracy, tested according to all applicable ANSI C12 testing protocols, from the Burbank Water and Power test shop. For all systems receiving PBI payments, the installed meter must be a separate interval data recording (IDR) meter or a complete system that is functionally equivalent to an IDR meter, recording data no less than at 15-minute intervals.

9.3.6 Glendale Water & Power Solar Solutions

The Glendale Solar Solutions Program provides all customer groups with an incentive to install PV systems on their homes and buildings. Rebates (up to 50 percent of total costs) are available for the installation of a PV system less than or equal to 30 kW. Larger systems can receive a rebate of $ 0.456 per kWh of actual electric production for the first five years. Systems must be sized to produce no more than 125 percent of the customer's past 12 month kWh consumption.

Glendale requires two meters, a net meter and a performance meter, on all installed systems. The program has an internal meter accuracy requirement of 0.5 percent for all meters that the City of Glendale deploys. Existing Glendale customers who install PV can use their current electromagnetic meter as the net meter. In addition, they receive a second electromagnetic meter from the utility that measures total production of the system. Both meters are read manually by meter readers on a monthly basis.

For new customer installations and those systems in inaccessible locations, Glendale installs a radio-enabled net meter and a radio-enabled performance meter. The meters were originally installed only on inaccessible systems; however, since they reduce meter reading time and error, Glendale now installs these meters on all new systems with no existing meter. The radio-enabled meters, which have a 2 percent accuracy requirement, can be read with a hand-held device up to 500 feet away.

9.3.7 NV Energy Renewable Generations Rebate Program

NV Energy administers the Renewable Generations Rebate Program for PV systems on behalf of the Nevada Task Force on Energy Conservation and Renewable Energy. Incentives are paid based on system capacity and customer type ($2.10 per Watt for residential and small business customers; $4.20 per Watt for public buildings). Rebates are limited to 5 kW for residential systems, 30 kW for small business and public/non-profit buildings, and 50 kW for schools.

Rebated systems are net metered with an Itron bi-directional, low-profile, revenue-grade utility meter. The low-profile meter is equipped with an internal clock, and time-stamped data is recorded in 15-minute intervals to ensure data quality. The systems are also equipped with a second performance, or REC, meter. This revenue-grade meter records PV system output over its lifetime and is used to verify RECs and count towards the utility's' goals under Nevada's RPS.

The meters are installed and maintained by NV Energy, but customers are responsible for installing the meter socket that complies with Utility Standards for Generation meter with the installation requirements as follows:

- ANSI standard 4 jaw socket
- 120/240 volts
- 100 amps or 200 amps depending on system size (may be larger on small business, school or public building projects)
- Single phase three wire
- UL listed, NEMA 3R
- Ring design
- No by-pass mechanism
- AC disconnect and generation meter socket must be located with 10 feet of the revenue meter

9.3.8 Public Service New Mexico Solar PV Program

PNM provides no upfront rebate for the cost of their customers' solar system. PNM uses a combination of net metering and REC purchases as their solar incentive.

- Net Metering: All residential solar customers are on a time-of-use rate. The customers pay more for and get paid more for electricity produced during peak hours, from 8 a.m. to 8 p.m. with rates varying by season and year. Money that is earned is accumulated and does not expire; customers may request checks on a monthly basis. Commercial customers have similar terms, but accounts are zeroed at the end of each month and any access balance cannot be carried forward.
- REC purchases: In addition to net metering, PNM pays residential customers $0.13 per kWh and commercial customers $0.15 per kWh for the ownership of their RECs.

PNM rebates PV systems that are interconnected to the grid. All customers have a utility-grade, bi-directional billing meter for net-metering that is paid for and maintained by PNM. The bi-directional meter must be programmable to keep track of the time that energy is produced and consumed. These meters have an accuracy requirement of ±2 percent and are tested at PNM before it is installed. PNM strives to meet a ±0.5 percent meter accuracy requirement.

In addition, all customers have a second meter to keep track of RECs generated by the solar system. Customers are responsible for installing the meter base for the REC generation meter, and PNM installs the REC meter. This REC meter should be physically located near the existing billing meter so that the meters can be read simultaneously by PNM. The REC meters have a ±1 percent accuracy requirement and meet ANSI C12 standards, which is consistent with the WREGIS's requirements. (New Mexico requires all RECs used for RPS compliance to be tracked through the WREGIS.)

Customer-sited distributed generation installations less than or equal to 360 kW in nameplate capacity can submit dynamic generation data to the WREGIS through a qualified reporting entity or WREGIS' Self-Reporting Interface. The WREGIS Operating Rules directs customer-sited generators that "the original data source for reporting total energy production must be from revenue-quality metering at the AC output of an inverter or generator For this class of generators, a revenue-quality meter and its installation must at a minimum meet the applicable ANSI C12 standard or its equivalent."

9.3.9 Arizona Public Service Solar Incentive Program

The Arizona Public Service offers an upfront capacity-based incentive to all solar customers following the schedule below in exchange for 20-years of RECs. Non-residential customers have the option of selecting production-based incentives under different terms of payment.

Table 9-4: APS Incentive Structure

		Up-front incentive	Production-based incentives (maximum incentive levels)			
		20-year REC agreement Incentive capped at $75,000	10-year REC agreement/ 10-year payment	15-year REC agreement/ 15-year payment	20-year REC agreement/ 10-year payment	20-year REC agreement/ 20-year payment
Non-Residential	Grid-tied	$2.50/watt	$0.202/kWh	$0.187/kWh	$0.250/kWh	$0.180/kWh
	Off grid	$1.50/watt	$0.121/kWh	$0.112/kWh	$0.150/kWh	$0.108/kWh
Residential	Grid-tied	$3.00/watt	Not Available			
	Off grid	$2.00/watt				

All on-grid systems paid with capacity-based incentives are net metered, and customers are paid based on their rate plan. Net metering is accomplished using a bi-directional meter, which is provided by the utility to each program participant at no charge. The meter accuracy requirement is ±3 percent, and they can be programmed to allocate production and consumption by time of use. Any customer's net excess generation (NEG) is carried over to the customer's next bill at the utility's retail rate as a kWh credit. Any NEG remaining from the customer's last monthly bill in a calendar year or at the time of a customer shut-off will be surrendered to the utility. For customers taking service under a time-of-use rate, off-peak generation will be credited against off-peak consumption, and on-peak generation will be credited against on-peak consumption.

Customers who opt for the performance-based incentive are required to have a generation meter and a dedicated phone line to communicate monthly production data to APS. The meter accuracy requirement is also three percent.

9.3.10 New Jersey Renewable Energy Incentive Program

The Renewable Energy Incentive Program offers upfront incentives to customers who invest in eligible electricity-producing equipment for use in offsetting onsite electric consumption. Incentives for PV systems are based on the rated nameplate capacity of the system installed. Under the 2009 program, residential systems up to 10 kW and non-residential systems up to 50 kW are eligible for incentives. Current incentive rates are:

- Standard residential (10 kW maximum): $1.55 per watt

- Residential w/energy audit (10 kW maximum): $1.75 per watt
- Non-residential (50 kW maximum): $1.00 per watt
- NJ-sourced bonus: $0.25 per watt for projects that use systems or components manufactured or assembled in New Jersey.

By 2021, New Jersey's RPS requires that 2.12 percent of the total generation from each electricity supplier/provider serving retail customers in the state comes from solar power. By this date, an estimated 1,500 MW will be required in New Jersey. New Jersey's Solar Renewable Energy Credit (SREC) Program provides a means for SRECs to be created and verified, and allows electric suppliers to buy these certificates in order to meet their solar RPS requirements. According to the New Jersey Office of Clean Energy (OCE), in October 2008 the weighted average price of 2009 SRECs was approximately $390/MWh ($0.39/kWh). However, the OCE reports an October 2008 high price of $600/MWh, and more recent trades may have exceeded this price.

All systems must have monitoring capability that is readily accessible to the owner. This monitor (meter or display) must at a minimum display instantaneous and cumulative production. An annual engineering estimate is used to calculate the monthly SREC generation for systems with a capacity less than 10 kW. The program's web site allows owners of systems with10 kW to 50 kW capacity to upload monthly meter readings and/or production information. Meters installed on these systems must meet ANSI C12 standards and be at least five percent accurate.

For systems greater than 50 kW, the systems must be metered by an ANSI C12-certified meter with at least one percent accuracy. Additionally, these generation data must be capable of automatic reporting to the SREC Administrator via electronic exchange. Annual inspections verify reported generation for a sample of all systems.

9.3.11 New York State Energy Research and Development Authority Solar Electric Incentive Program

NYSERDA provides incentives of $2 to $5 per watt (DC) to eligible customers for the installation of approved, grid-connected PV systems. The maximum capacity supported by the program is eight kW for residential systems; 80 kW for non-residential systems; and 25 kW for non-profits, schools, and municipalities. Larger systems are eligible for incentives, but incentives may only be received for installed capacity up to the program caps. Participating installers are required to provide energy and power production data to NYSERDA two times each year for each of the first three years of system operation. For systems smaller than 25 kW, meters must be read at least once every six months; for systems 25 kW and larger, meter readings must be taken monthly.

In Section 4 of NYSERDA's *PON 1050 Eligible Installer Agreement*, NYSERDA requires:

"…each PV system to include, at a minimum, a meter or meters displaying (a) instantaneous AC power, and (b) cumulative total AC energy production. Such meter(s) must have minimum accuracy of 5% and a certificate of compliance from the manufacturer. Remanufactured utility-style meters are permitted if they are certified as calibrated to applicable ANSI standards for electricity metering. The meter(s) must include numerical displays ("easy-read type") in watts or kilowatts for power and kilowatt-hours or megawatt-hours for energy. The energy metering data must be automatically stored independently of the inverter display. Examples include a separate utility-style meter or an inverter-based monitoring system that exports data at least daily to a computer for storage. The energy value displayed should be the total production for the life of the system. Battery-based systems may require multiple energy meters to capture the net production considering the critical load panel, export to the grid and import from the grid for battery charging."

New York requires that net metering is available to all distributed generators. According to program staff, the DPS requires that all meters installed for all customers meet an accuracy standard of ±2 percent, even though the DPS states in its 2003 operating manual that "no new watt-hour meter shall be placed in service unless test results indicate a registration between 99.2% and 100.8%." Additionally, the utilities require that all meters comply with ANSI C12.1. Depending on the specific utility that the customer is under, there could be one or two meters to measure both electricity consumption and production. If there is one meter, then it tracks both the net flow of electricity and the total generation of the system. Some utilities also offer time-of-use pricing and install programmable meters that record the time of electricity production and consumption.

The New York DPS is currently piloting an advanced meter infrastructure program throughout the state. All programs are approved through the DPS, but are implemented by the utilities. Installed meters must meet the following requirements:

- Comply with all applicable ANSI standards, commission regulations, and Federal standards
- Provide net metering
- Provide a visual consumption read, either at the meter or via an auxiliary device

- Provide time-stamped interval data with minimum interval of one hour
- Have sufficient on-board memory to store collected data for 60 days
- Provide customers and AMI system operators with direct, real-time access to electric meter data in an open, non-proprietary format
- Have ability to remotely read meters on demand
- Have two-way communication capability, including ability to reprogram the meter remotely without interfering with the operation of the meter
- Have ability to send signals to customer equipment to trigger demand response functions and connect with a HAN to provide direct or customer-activated load control
- Have appropriate security capabilities, as outlined in the DPS proceeding *CASE 09-M-0074 – In the Matter of Advanced Metering Infrastructure.*

Currently, few systems have been installed with these capabilities, which independently vary by system classification and/or urban, suburban, or rural setting.

9.3.12 Massachusetts Technology Collaborative Commonwealth Solar

Launched in January 2008, the Commonwealth Solar program facilitates installation of 22 MW of new solar projects by 2012, towards meeting the goal of 250 MW of installed solar in the State of Massachusetts by 2017. Backed by $68 million in dedicated funds over a five-year period, the program promotes installation of PV projects at residential, commercial, industrial, and public facilities through incentives. Commercial PV projects are eligible for rebates up to 500 kW and residential projects are eligible for up to 5 kW.

In 2009, the base residential rebate is $1.00 per DC Watt, with supplemental incentives for customers with a moderate home value ($2.00), moderate income ($1.25), or utilizes in-state components ($0.15). The rebate is capped by the lesser of either a 5 kW system or $20,000 per project. The base incentive level for non-residential projects is split into four tiers ranging from $1.40 to $3.15 per DC watt; smaller systems are eligible for a higher rebate. Like the residential rebate structure, non-residential customers are eligible for supplemental incentives of $0.15 for using in-state components and $1.00 for systems installed on public buildings.

All Commonwealth Solar projects must have a dedicated revenue-grade production meter that:

- Is readily accessible and easily understood by the PV project owner
- Records the PV project's AC output, as measured on the AC side of the PV project's isolation transformer. For DC-only PV projects, the meter should record the PV project

output provided to the facility load. If a storage device is integral to the PV project, the meter should record the output from the storage device.

- Shall be separate from the utility billing meter and shall not interfere with utility billing or net-metering
- Must be a standard utility-grade meter that conforms to applicable ANSI C12 standards
- Shall have a visible display of cumulative energy produced by the PV project and be available for periodic testing and/or re-calibration, if necessary.
- Has a two-year product warranty.

MTC recommends that PV projects less than or equal to 10 kW voluntarily report to a performance tracking system (PTS). For PV projects larger than 10 kW, PV projects must automatically report to the PTS for five years. The PTS is used to support the market for RECs and to help MTC monitor PV project performance. There are three options for automated reporting to the PTS:

- Vendor-Supplied System: A data acquisition system (DAS) that has local PTS-incorporated automated reporting features
- Vendor-Supplied Service: A DAS with a service that offers remote monitoring and has PTS-incorporated automated reporting features
- Sample Source Code Integration: A DAS vendor or service provider who can customize their system's software to incorporate this data transfer functionality.

PV system owners can sell RECs generated by their systems to the Energy Consumers Alliance of New England at $0.03 per kWh for a three-year period. Energy Consumers Alliance of New England is a non-profit organization that buys PTS-verified RECs and sells them to a green power program offered by a local investor-owned utility.

Further details about metering and automated reporting requirements can be found at: http://ar.masstech-pts.org/downloads/. This site includes *FAQ: Metering Requirements For The MTC Production Tracking System (PTS), Automated Reporting Guide for the MTC Production Tracking System*, and automated reporting XML schema and sample codes that demonstrate automated reporting.

9.3.13 Gainesville Regional Utilities Residential Solar Rebate Program and Solar Feed-in Tariff

The Gainesville Regional Utilities provides a capacity-based incentive to their residential customers in return for RECs. GRU also provides a first-of-its kind feed-in tariff (FIT) in the U.S. for its business customers. Customers signing on to the FIT invest in their own PV system to generate electricity and are under contract for 20 years at a fixed price. (The first price offering was $0.32/kWh.) These customers then sell energy directly to GRU.

Capacity-based residential systems receive a net meter. The GRU pays customer's at the prevailing net metering rate for excess energy generation. There are no additional metering requirements.

FIT systems are not net metered, but receive a generation meter. GRU adheres to the Florida Public Service Commissioner's (FPSC) guidelines for all revenue meter installations. The FPSC requires that watt-hour meters adhere to ANSI C12.1 guidelines when installed and that watt-hour meters in service register within two percent accuracy. The GRU programs, tests, and installs each meter used in PV installations only if it meets the Florida Public Service Commissioner standards.

The bulk of the systems participating in this program thus far are small systems under five kW. For small systems, the net billing meter and FIT generation meter are both read monthly by GRU's meter readers. There are FIT systems scheduled to come online whose output will be greater than 400 kW. For these large systems, the generation meters will have unique IP addresses that can be read remotely via a wireless phone line. The data retrieved from these meters is compatible with Itron's MV-90 MDM system.

9.3.14 Queensland, Australia Solar Bonus Scheme

PV customers consuming no more than 100 MWh of electricity a year are eligible for Queensland's Solar Bonus Scheme. Customers participating in the scheme are paid $0.44 per kWh for surplus electricity fed into the grid—around three times the current general domestic use tariff of $0.1629/kWh. The Solar Bonus Scheme is essentially a net-metering program with a favorable export rate.

Customers who wish to claim the solar bonus need electricity metering that separately records electricity imports and exports. Customers with an existing solar PV system wired in a gross metering configuration need to rewire their system to a net configuration in order to participate in the scheme. Customers who wish to change their metering arrangements need to consult with their electricity suppliers.

The metering relevant to the Queensland program is owned, installed, and operated by the customer's energy company. The customer's energy company installs an electronic bi-directional meter at the revenue metering point. Connection point of the solar system may be done at either a distribution switchboard or power circuit associated with the principal tariff within the customer's installation. This connection cannot be made at a remote metering panel. The energy company will configure the metering to register imported and exported energy.

The customer must pay for all costs incurred for wiring and/or metering changes, including modifications to the customer's switchboard. For systems greater than 10 kilovolt ampere (3 phase) or 3 kilovolt ampere (single phase), the customer may be required install an advanced meter. The customer must also supply the energy company with safe access to install, test, maintain, or remove the meter.

9.3.15 German Feed-in Tariffs "Einspeisevergütung"

Solar customers in Germany are currently paid €0.32 ($0.42) per kWh of AC electric production for the first 20 years for ground-mounted systems and €0.43 ($0.56) for roof-mounted systems. These rates are fixed by the government and decrease each year, but are about 50 percent higher than residential traditional retail electricity rates in Germany.

German homes with PV installed have two meters, both provided by the grid operator. One meter is the electromagnetic, manually read home electricity consumption meter that all German homes have, which are connected to the grid. When a PV system is installed, a second meter of the same type is placed just after the inverter (electricity consumption meters are installed before the inverter) and measures total AC kWh produced. Both meters are required to be checked by the local bureau of standards (*Eichamt*), and have an official verification certificate, certifying that they meet standards set by the *German Physikalisch Technische Bundesanstalt.*[15]

[15] The *German Physikalisch Technische Bundesanstalt* is the national metrology institute providing scientific and technical service. Its core competence includes measuring metrology with the highest accuracy and reliability.

Each month, PV system owners receive an installment payment from the electricity distribution company for their estimated yearly energy generation. After the annual meter production meter reading, the distribution company produces a final bill or payment for the PV owner. Distribution companies have a legal obligation to buy all the solar power produced at the government-defined rate.

10. Section H – Current Market Drivers and Future Developments

This section provides an assessment of the current status of the solar PMRS market and its future developments. In 2009, KEMA interviewed twenty-six industry stakeholders, including PMRS providers, PPA providers, contractors, solar customers, and researchers, to piece together a picture of the current PMRS market status and future developments.

10.1 PMRS Market Participants

All market stakeholders KEMA interviewed are active in California; some are also active in New Jersey, New York, Arizona, Connecticut, Nevada, Massachusetts, Delaware, Colorado, Hawaii, and Oregon. Although the interviewees are only a portion of the entire PMRS market, they represent a diverse group. The following list provides a synopsis of the characteristic of the interviewees.

- PMRS providers: Most sell to large PPA providers or installers. Their solar customers are mainly commercial customers with some educational institutions. Most PMRS providers conduct in-house research and development (R&D) to advance their products.
- PPA providers: They sell mainly to commercial customers; some also sell a small percentage to residential customers, governments, and utilities. PPA providers tend to use the same PMRS provider for all of their projects; some have their own PMRS system.
- Contractors: They sell either to PPAs or directly to solar customers. Their solar customers consist of large commercial customers mainly, and a smaller percentage of government, industrial, and agriculture customers. Like PPA providers, contractors usually use the same PMRS for all their projects or use their own product.
- Solar customers: KEMA interviewed five solar customers, including an educational institution, a government building, a fire station, a food processing facility, and an airport. When choosing a PMRS provider, solar customers tend to use referrals from their installers.
- R&D Organizations: KEMA interviewed two R&D organizations, including CEC Public Interest Energy Research (PIER) and Department of Energy, National Renewable Energy Laboratory (NREL).

Some vendors are vertically integrated at some level or the other. For example, a solar equipment manufacturer could provide installation, financing, and PMRS bundled together; some installers or PPA providers have their own PMRS product; and some contractors or PPAs have their own PMRS software, but rely on a hardware integrator to provide meters. The complete list of interviewees is provided in Appendix H.

Interview findings will be summarized by the following categories:

- Market Drivers
- Market Challenges
- PMRS Products Needs and Gaps
- Product and Technology Trends
- Challenges in Technology Development

10.2 Market Drivers

PMRS usage on solar systems is becoming increasingly popular. The primary PMRS market driver is to optimize solar system production; this is especially important for PPA providers whose revenue is tied to system production. There are many other reasons cited by market participants for their PMRS purchase. The reasons are different for different stakeholders. For example, energy managers use PMRS for maintenance and commissioning; solar programs may require its use for distributing performance-based incentives; PPA providers use it for billing customers; and educational institutions use it for demonstrating the benefits of solar power.

The major PMRS market driver is to optimize solar system production. Solar customers, especially PPA providers, want to monitor their systems to ensure optimal system generation to provide maximum financial and environmental benefits. If the PMRS indicates that the solar system is not performing as well as expected, fixes can be made immediately. Some PMRS are able to monitor each panel or string on the system individually. For customers, installers, or PPAs who have multiple sites to monitor, PMRS can aggregate the data for ease of monitoring. In addition, PMRS can offer an interface for multiple users to access performance data from the same system.

Some installers use PMRS to provide performance guarantees to their customers; having PMRS as part of their service often offers a competitive advantage to installers. One PMRS even offers “white label” systems that installers can brand as their own and bundle with their installation service.

Interview respondents revealed mixed feelings about how incentive program requirements affect the PMRS market. The CSI requires PMRS and data reporting for PBI incentive payments, and it would be expected that the CSI is the main driver of PMRS purchases in California. However, the interviewees revealed that the CSI does not seem to be a major driver for the PMRS market. Though many PMRS providers and contractors think that the CSI makes market conditions more favorable by requiring PMRS for large systems, most think that large solar customers purchase the PMRS for system performance monitoring, maintenance, and other purposes. PPAs consider PMRS essential to operating a solar power plant. All interviewees invariably said that they expect to either offer PMRS or purchase PMRS, even after the CSI ends in 2017. In fact, some customers interviewed purchased the PMRS before it was required by the CSI or were not aware that PMRS was a requirement for large systems.

Although CSI does not seem to be a major driver for the PMRS market, the NYSERDA PV incentive program was cited as a major driver by at least one PMRS provider. NYSERDA PV installers are required to provide performance monitoring and data reporting annually for the first three years of system operation. In addition, the energy metering data must be automatically stored independently of the inverter display; therefore, some installers might use a PMRS that periodically exports data to a storage computer for annual reporting to NYSERDA.

In New Jersey, although the accounting and sales of SRECs is voluntary, they are a major part of the solar program’s incentives. Systems lower than 10 kW can estimate RECs based on an engineering estimate; however, systems 10 kW or larger must upload monthly meter readings and production information to the program website. PMRS facilitates this system production data collection and reporting for SRECs trading.

Similarly, PPA providers bill their customers based on solar generation. PMRS facilitates the collection of generation data for billing purposes.

Large energy customers are becoming more sophisticated. Not only do they generate their own energy using solar PV, many also have building management systems that manage on-site usage. PMRS facilitates the integration of solar production data to the building demand management system in order to create a comprehensive view of a site’s energy production and usage.

Educational institutions find it highly effective to use PMRS data to create public awareness and showcase the benefits of solar. Some PMRSs have graphic and user-friendly displays to show real-time production data, which is an interesting and interactive way to illustrate how a solar system works.

10.3 Market Challenges

While some PMRSs are not experiencing many market challenges, as evidenced by their growing market share and abundance of customers, others have identified some impediments in the market. The slow down of the solar market was identified as an indirect barrier to PMRS market growth. Other market barriers included lack of industry standards, costs, lack of customer awareness, and inadequacy of current market offerings.

PMRS is directly linked to the solar industry, especially the market for large commercial and industrial solar systems. The challenges and slow down of the current solar market directly affects the PMRS market and is preventing its growth. Some challenges that solar currently faces include the scarcity of credit financing, slowing economy, difficulties obtaining permits, interconnection rules complications, inadequate building structures, contractor inexperience, lack of installation requirement standardization, unfavorable rate plans, and uncertainty in incentives.

The lack of data standardization and specification of minimal monitoring requirements are challenges that affect all emerging technologies. All survey respondents favored adopting some standards to ensure quality and consistency. Some PPA providers were concerned about the lack of data standardization. Not only do data standards provide consistency, they should ensure data accuracy, security, and storage so that any piece of data can be traced and verified. The current CSI requirement for PBI monitoring is 2 percent; however, most PPA providers look for accuracy level higher than 0.5 percent; and most PMRS provides meters that surpass CSI's 2 percent metering requirement. Some industry participants questioned why CSI's standard is much lower than the normal industry practice. Two PPAs suggested that CSI should be concerned with the combined system accuracy instead of just the metering accuracy.

Price was one reason PMRS is not as widespread as it should be, especially for smaller solar systems. A low-cost system is as low as $450 for a 5-year package; however, most systems cost several thousand dollars, including installation and annual monitoring fees. Some packages keep the cost down by not installing weather monitoring systems or wireless communications. One vendor who monitors systems by panel charges $2 per panel annually.

Except for this vendor, PMRS is not modularized like the PV panels; therefore, the smaller the system, the less incentive there is for an owner to pay for an expensive monitoring system. PMRS is useful for monitoring performance and maintenance to optimize solar benefits; however, it is only economically feasible if the cost of PMRS does not cut into the return on investment; that is, the cost of monitoring should not exceed the value gained from monitoring. The industry is not showing any price trends; though a few stakeholders have seen increases ranging from a few percent to 50 percent. Most think the PMRS price cap should be less than 3 percent of total system cost. One PPA/PMRS provider thinks that PMRS should be a required component of any solar system and that any measure prescribing percentage caps to total system cost is meaningless.

Some PMRS providers and contractors stated that customers need to be educated about the benefits of PMRS. They did not believe CSI did enough to promote the benefits of system monitoring and performance optimization. Some solar owners are only concerned about meeting the minimum program requirements in order to receive their incentives, instead of purchasing the best PMRS for their solar system. Some owners did not understand that many PMRS systems can pay for themselves (and exceed the original cost of PMRS) when realizing benefits of optimizing performance. Some PMRS providers think CSI needs to further educate system owners about the value of PMRS, and perhaps increase cost caps, which will require more systems to include PMRS.

Overall, customers expressed satisfaction with their PMRS. However, some felt that there were not adequate numbers of PMRS providers or products to meet customers' needs. Below, some of the features customers look for in PMRS and industry technology trends are discussed.

10.4 PMRS Product Needs and Gaps

While some customers choose the lowest cost PMRS that meets program requirements, most PMRS customers look for specific features in a PMRS product. During interviews conducted in early 2009, PMRS features customers needed versus those nice-to-have were identified and are provided in Tables 10-1 and 10-2. Interviews also identified for gaps in the PMRS industry where products do not meet needs of customers.

Table 10-1: Necessary PMRS Features

Features considered necessary within the industry	
Minimum meter	Most PMRS users look for ANSI C12 certified revenue-grade meters

Features considered necessary within the industry	
accuracy	that are 0.5 percent or better. PPA providers would be expected to be concerned about metering accuracy than other PMRS users. When interviewed, many PPA providers indicated they had not thought much about minimum metering accuracy, stating they do not specify minimum accuracy in their contracts, but leave the decision to their PMRS providers. Most tend to use meters with 0.2 percent or 0.5 percent accuracy. However, one PPA provider was satisfied with 1 percent meters. Another PPA provider noted a comparison between the readings from their 0.5 percent meter and 5 percent inverter readers and found them to be close enough; although 5 percent meters lose some accuracy, readings typically even out over a period of time.
Meter data quality	Two PPA providers expressed the critical importance of meter data quality. One PPA provider was frustrated by the quality of meter data offered by current PMRS providers. The provider believed that meters should be time synched to the national clock, similar to AMI meters. Additionally, a secured audit trail should be available and retained for at least 60 days.
Performance benchmarking	Solar customers believed that performance benchmarking was an important PMRS feature. However, only half of the PMRS providers and contractors interviewed stated that performance benchmarking was a contract requirement. PPA providers indicated that performance benchmarking was not an important feature.
Weather stations	Weather monitoring was important to PPA providers who use weather data to consider operating performance ratios. Educational institutions found weather monitoring an important part of their solar project.
Multi-site monitoring	This feature is required for contractors and PPA providers who have multiple sites to monitor simultaneously.
Automated alerts	Automated alerts that warn users of anomalies were found to be a key PMRS feature. Users also preferred the ability to set their own performance threshold.
User-friendly interface	Most interviewees considered a user-friendly interface critical for a PMRS. This was particularly important for educational institutions and other customers who wanted to show their systems to visitors. Some contractors use PMRS displays as part of their sales tools.

Features considered necessary within the industry	
Ease of installation	Installation and integration simplicity to the rest of the solar system was important to most customers and installers.
Customer service	Responsive technical support and customers service was stated as a necessary feature to most customers.

The following PMRS features were not deemed critical or necessary, but were considered advantageous for some types of projects.

Table 10-2: Important PMRS Features

Features considered as important but not necessary within the industry	
String-level monitoring	String-level monitoring helps a user pinpoint anomalies in a string. This feature was required by one PPA, but not mentioned by others.
DC monitoring	DC monitoring helps a user identify if a system anomaly occurs before or after the inverter. This feature was requested by some PMRS customers and contractors.
Automated reporting to CSI	Customers found it more convenient if their PMRS provider was also their CSI PDP for PBI payments.

One of more interviewees expressed an interest for the following features (Table 10-3) to be introduced to the market, though they are not yet available.

Table 10-3: Desired PMRS Features

Features that are not yet available in the market	
Better meter data quality	One PPA provider expressed frustration by the quality of meter data offered by current PMRS providers. The provider believed that meters should be time synched to the national clock, similar to AMI meters. Additionally, a secured audit trail should be available and retained for at least 60 days.
Automatic bill generator	This would enable PMRS providers to automatically generate bills for PPA customers.
Bi-way communication with inverter	This feature would oppose UL certification; however, one PPA provider cited that the ability to change settings on inverters is critically important.

Features that are not yet available in the market	
Hardware and software separation	While some customers prefer a packaged PMRS system, other customers, like PPA providers, prefer PMRS hardware and software to be sold separately. Unbundled components offer an owner the flexibility to choose equipment.
BAS/EMS integration	Not all interviewed customers had building automation system or energy management systems; however, integration with the solar PMRS would be advantageous for large customers who do have these systems. PPAs find this an emerging need as more customers inquire about BAS/EMS integration. This feature could be particularly important for educational solar projects.
Communication with smart meters	Some customers thought communication with smart meters was important, though most interviewees did not.

10.5 Product and Technology Trends

While some industry participants felt that PMRS technology was straight-forward with little opportunity for innovation, others believed it was constantly evolving. There are some emerging product trends, many of which have already been mentioned above as desirable product features.

Table 10-4: PMRS Product Trends

PMRS product trends	
Web-based interface	Like many business and consumer products, PMRS products are also trending towards using a web-based interface. Some products allow users access to PMRS data at different user levels from different locations.
Sophisticated displays	Displays are becoming more sophisticated and user-friendly, especially, for educational projects. For example, some PMRS displays correlate the amount of solar generation to carbon offsets, or the number of trees preserved.
Multi-site monitoring	Multi-site monitoring is useful for energy managers, contractors, and PPA providers who oversee multiple solar sites.
String-level and	String-level and panel-level monitoring helps users pinpoint anomalies.

PMRS product trends	
panel-level monitoring	For example, there have been episodes where panels are being stolen at night; it would be helpful if an alarm were triggered when a circuit was disrupted. Although this type of monitoring is an emerging trend, it may unnecessarily complicate a simple system. It may be helpful for a system affected by external design factors like shade, but it is generally not cost effective for most systems.
Improved accuracy	The industry is experiencing data accuracy improvements, either through hardware or software improvements.
More sophisticated analysis tools	Energy analytical tools are becoming more sophisticated, instead of simply collecting and displaying performance metering data. For example, a PMRS can calculate solar savings based on actual tariff rules, and there are simulations that determine what combination of rate plan and solar radiation a PPA needs in order to meet a specified return on investment.
Separation of software and hardware	The industry is trending towards a separation of PMRS components, so a customer can specify software or hardware, but have the PMRS provide the remaining system components.
Wireless monitoring	The industry is trending towards using wireless monitoring, e.g., cellular based technologies, instead of hard-wired communication lines.
Integration with demand management	More customers are considering demand management services, as they become more sophisticated in their overall energy management. The prevalence both customer-owned solar generation and demand management systems will lead to more integration of PMRS with demand management tools, such as building automation systems and energy management systems.
Solar and smart grid integration	Industry participants thought that solar integration with the smart grid was important to their R&D. In fact, some are already conducting R&D on communication between solar systems with the utility smart meters. Most interviewees believe solar integration with the smart grid will occur in the near future—within the next 10 years. Others believe integration will occur sooner—within the next 2–5 years. Ultimately, solar and smart grid integration depends on the focus of the utilities. Only a few survey respondents thought that it would take at least 25 years for solar-smart grid integration.

Since government research institutes are current with technological developments, scientists from CEC PIER program and NREL were interviewed for this study. PIER is emphasizing renewables and grid integration; however, the program is not specifically targeting PV R&D in the long term. CEC PIER program staff observes that PMRS with multi-site solar monitoring is already being experimented with for community-scale integration and micro-grid type applications. NREL is monitoring a large subdivision of hundreds of homes with 2-3 kW rooftop PVs to research distribution system impact with high PV penetration. For PMRS products, NREL indicates that weather monitoring is critical, while performance benchmarking and minimum meter accuracy are important; but DC monitoring is not very important to their research. Smart grid and solar integration is increasingly important in R&D for the industry.

10.6 Challenges in Technology Development

The main technical challenge the industry faces is lack of standards, including equipment, safety, and performance standards, and smart grid specifications. Under the current poor economy, the industry is preserving funds for the most critical technological research. However, the availability of industry standards would provide a better, more unified direction around which the industry could develop products. Since the concept of “smart grid’ is not clearly defined and with no set specifications, it is difficult for the industry to develop products that cater to smart grid integration. This sentiment was also echoed regarding the lack of standard communication protocols for energy management systems and HANs. Other technological challenges include the lack of internet connectivity at some customer locations and the design of hardware (e.g., meter, data logger, etc.) that remains reliable in prolonged outdoor exposure. NREL staff specifically mentioned the difficulty in monitoring the power quality of distribution transformers, because pad-mounted transformers encased in steel can heat up to 200°Fahrenheit and meters normally stop at 130°-180°Fahrenheit.

11. Glossary

AC	alternating current
AHJ	authority having jurisdiction
AMI	advanced metering infrastructure
AMR	automatic meter reading
ANSI	American National Standards Institute
APS	Arizona Public Service
ASHRAE	American Society of Heating, Refrigeration, and Air Conditioning Engineers
B2G	building-to-grid
BACnet	building automation and control network
BAS	building automation systems
Btu	British thermal unit
C&I	commercial & industrial
CAISO	California Independent System Operator
CCSE	California Center for Sustainable Energy
CEC	California Energy Commission
CIS	customer information systems
CPAU	City of Palo Alto Utilities
CPP	critical peak pricing
CPUC	California Public Utilities Commission
CSI	California Solar Initiative

CT	current transformers
DAS	data acquisitions system
DC	direct current
DG	distributed generation
DR	demand response
DPS	Department of Public Service
DSIRE	Database of State Incentives for Renewable Energy
EDI	electronic data interchange
EPBB	expected performance-based buydown
EPBI	expected performance-based incentive
ERP	emerging renewables program
FIT	feed-in tariff
FPSC	Florida Public Service Commissioner
FTP	file transfer protocol
G2B	grid-to-building
GHG	greenhouse gases
GRU	Gainesville Regional Utilities
HAN	home area network
HAS	home automation systems
HW	hardware
IBC	intelligent building control

IDR	internal data recording
IEC	International Electrotechnical Commission
IED	intelligent electronic devices
IOU	investor-owned utility
IP	internet protocol
kbps	kilobytes per second
kW	kilowatt
kWh	kilowatt hour
LADWP	Los Angeles Department of Water and Power
LAN	local area network
LSE	load-serving entity
MAN	metro area networks
MDM	meter data management
MIU	meter interface units
MTC	Massachusetts Technology Collaborative
MWh	megawatt hour
NCU	network control units
NEC	national electrical code
NEG	net excess generation
NREL	National Renewable Energy Laboratory
NRTL	nationally recognized test labs

NYSERDA	New York State Energy Research and Development Authority
OCE	Office of Clean Energy
OEM	original equipment manufacturer
OSHA	Occupational Safety and Health Administration
P2P	point-to-point
PA	program administrator
PBI	performance-based incentive
PDP	performance data provider
PG&E	Pacific Gas & Electric
PIER	Public Interest Energy Research
PLC	power line carrier
PMRS	performance monitoring and reporting services
PNM	Public Service New Mexico
PTS	performance tracking system
PV	photovoltaic
R&D	research & development
REC	renewable energy credit
RF	radio frequency
RFP	request for proposal
RPS	renewable portfolio standard
SCADA	supervisory control and data acquisition

SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SMUD	Sacramento Municipal Utility District
SOW	scope of work
SREC	solar renewable energy credit
SW	software
TOU	time of use
TREC	tradable renewable energy credit
U.S.	United States
UL	Underwriters Laboratories, Inc.
VEE	verification, editing, and estimation
VFD	variable frequency drive
WAN	wide area network
WREGIS	Western Renewable Energy General Information System

Appendix A: KEMA Research Plan

CSI Research Plan

For metering, monitoring and reporting market for Photovoltaic systems in California

Version 1.0

December 24, 2008

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1. Introduction

This project involves the application of multiple layers of expertise and experience and this Research Plan includes the goals, schedule, and methodology for completing the Scope of Work for this project. The Scope of Work has been divided into 9 sections (Sections A through H), which encompass the 14 original major task deliverables, plus the added task of developing a 5% meter specification. This Research Plan is divided into separate sections to address these 9 areas of research and align with the Scope of Work. These areas are:

- **Section A** - Hardware and Equipment Review of Industry Solar Projects
- **Section B** - Installation Services
- **Section C** - Data Transfer
- **Section D** - Performance Monitoring and Reporting Service Providers
- **Section E** - Compare CSI Requirements with Hardware, Labor, and Service Offerings
- **Section F** - Integration of CSI Metering Requirements and the Advanced Metering Initiative
- **Section G** - Compare CSI Metering Requirements to Other Renewable Energy Incentive Programs
- **Section H** - Current Market Drivers and Future Developments
- **Section I** – Meter Specification

The tasks to perform the research can be organized into four major categories:

1. **Survey and Evaluation of Existing CSI Products and Services**, which includes Sections A, B, D and E (described in Section 2 of this Research Plan)
2. **AMI Integration with CSI** which includes Sections C and F (described in Section 3 of this Research Plan)
3. **Market Assessment of Solar Metering**, which require input from Sections A and G and which include combining the work from Sections G and H with other areas (described in Section 4 of this Research Plan)
4. **Meter Specification -** Development of a 5% meter specification for inverter-integrated meters used in EPBB programs (described in Section I of this Research Plan)

To perform the research in an optimal manner in the shortest period of time, the phases to complete the research are outlined in the following sub-sections.

1.1 Phase 1

- Concentrate on Phases A, C and F and I, which can be started concurrently. Phase A data is utilized in Phases C and F, and also in Section H. Section I has the highest priority for completion
- Start Section G and concentrate on identification of national and international renewable energy incentive programs. The number of programs evaluated will be limited to those with most relevance to the CSI program
- Start Section H
- Establish a weekly conference call to review project progress and status. Calls to be scheduled by SCE
- Create and distribute detailed project schedule in MS Project format
- Estimated completion for Phase 1 is by end of February, 2009. This is based upon approval of the Research Plan by January 9, 2009
- Complete Section I and distribute meter specification for review and comment

1.2 Phase 2

- Complete research for Sections A, C, F and create preliminary reports for each section for review and comment
- Complete data collection and research for Sections G and H
- Start Sections D and B
- Estimated completion date for Phase 2 is March, 2009

1.3 Phase 3

- Complete Sections D and B
- Complete Sections G & H (Although SCE has placed a priority on G & H, they represent the culmination of everything else)
- Estimated completion of Phase 3 is April, 2009 for submission of initial drafts of all eight final reports. Review by all parties and submission of final reports is anticipated to take up to an additional 5 weeks

The following sections define the specific objectives and proposed methodology for completing each task.

Research

Survey and Evaluation of Existing CSI Products and Services

2.1 Section A – Hardware and Equipment Review of Industry Solar Projects

2.1.1 Objectives

The objectives are to review the metering hardware and equipment currently being utilized for solar projects. This will be accomplished through three tasks:

- Task 1 – Identification, Description and Assessment of Major System Components
- Task 2 – Detailed Description of System Hardware Components
- Task 3 – Written Review of Meter and Meter Component Distributors

Survey tools will be developed to determine the characteristics and functionality of PMRS offerings and metering hardware being used in solar projects. Metering hardware is fairly straight-forward with a few general options being available, but PMRS systems aren't as simple. There's no single PMRS architecture that can be evaluated, so an understanding of each PMRS system must be understood and quantified.

2.1.2 Background and Significance

The requirement for a system output meter has been in place since 1998 under California's old Emerging Renewables Program (ERP). Over the years, the types of metering and information systems being used with PV systems have changed dramatically. Many new output metering types now exist and these have been reviewed by KEMA and added to the CEC's list of eligible equipment. When the pilot Performance Based Incentive (PBI) system was added to the old ERP, there became a new requirement to include revenue grade output meters. It was soon discovered that what the CEC envisioned for revenue grade metering systems did not exactly match the requirements from the California Investor Owned Utilities (IOU's).

Many of these metering issues were exacerbated as the California Solar Initiative came into being. As part of our commitment to the CSI effort, KEMA personnel have expended energy and effort with various meter manufacturers and with Metering Subcommittee Chair Persons to help determine a practical means for accepting PV output metering systems as revenue grade.

The California Solar Initiative (CSI) currently lists 34 firms who are classified as Performance Monitoring & Reporting Service Providers (PMRS). Within this space there are some providers who utilize packaged systems that include the installation of an output meter while some others simply tie into an inverter-based meter.

Previously one of the qualification requirements for a PMRS was to be independent from any manufacturer or installer of PV equipment. However, a recent ruling eliminated this restriction. As a result, there are several PMRS providers on the listing who are also manufacturers of inverters, PV modules and installers.

A challenge with gathering PMRS information is that the PMRS providers simply needs to self-certify to get on the CEC eligible equipment list. All prospective PMRS providers need to fill out and sign a form indicating that they comply with all the specific PMRS requirements. They are not required to give any specifics behind the hardware they use, the features of their system or cost estimates for installation or monitoring.

The electric metering associated with this service can either be of revenue grade (defined as +/- 2% accuracy for the CSI program) or non-revenue grade (defined as +/- 5% accuracy for the CSI program). Revenue grade metering is required for PBI payments and these 2% meters must be certified by an independent testing body to the accuracy requirements of the applicable ANSI C12 standard. Non-revenue meters can be self-certified by the manufacturer (according to the CSI Handbook). However, at the present time, there is no standard test protocol to ensure this accuracy. Traditionally, manufacturers of revenue grade meters, although they test to accuracy standards, often are not required to send units out to third party verification agents. Normally, the utility acceptance process is to have the meters calibrated with a certificate of calibration included, and some manufacturers will perform accuracy testing in-house on a sampling of the meters they produce. This process is not currently required under the CSI program.

Although each PMRS provider must conform to the same general requirements as defined in the CSI Handbook, there are variations in how each provider actually implements their services. These differences have not been delineated. For instance, some systems interface with output meters that are provided, some interface directly with inverter based metering systems and others provide additional data loggers.

Recently, an option for solar thermal systems has been added to the CSI Handbook. Both electric generation and heat generation (for electric use avoidance) solar thermal systems can be included. Heat generation systems would require a qualified Btu meter for measuring output and calculating the electric use avoidance. To date not a single manufacturer of a solar thermal unit or metering device has applied for inclusion on the CSI listing.

KEMA currently has a contract with the CEC where the eligibility evaluation for all PMRS providers and system output meters is performed. Under this agreement, each PMRS and meter manufacturer must send the necessary documentation to KEMA in order to be included on the CEC's listing. Through this eligibility effort, KEMA has a current working knowledge of each PMRS provider.

2.1.3 Research Design and Methods

Task 1 – Identification, Description and Assessment of Major System Components

KEMA will develop a web-based survey and e-mail the link to PMRS providers. The survey will provide details of each PMRS system including testing & certification, communication devices, warranties, any required maintenance and system costs. Since each PMRS has applied through KEMA for inclusion on the CEC listing (each PMRS is familiar with KEMA), the response rate to the survey will likely be higher than typical response rates. If necessary, KEMA will follow-up via telephone with any PMRS that has not responded to the web-based survey.

To optimize a vendor's response, KEMA will likely develop a web-based survey tool that will be used to solicit all the required information from each PMRS. Vendors will be contacted and given the web link. As necessary for completeness, a follow-up phone call would be made.

a. KEMA will identify and catalog the various components of performance-monitoring systems offered by the PMRS and how they interconnect. This will detail the types of meters that are used.

b. The assessment will identify testing and certification entities, practices and standards. This will include national and international organizations for meters and metering systems.

c. A listing of compatible communications networks will be identified for each of the applicable metering element. This will include wireless services, such as cellular, WiFi, WiMax, etc. and wired services such as broadband, Ethernet, telephone.

d. For each of the respective elements provided the listing will include cost ranges and typical or targeted costs.

e. The listing will include information on warranty type, duration and options for extended services. Costs associated with this service will be included.

Task 2 – Detailed Description of System Hardware Components

KEMA will develop a survey to capture information on each hardware component.

a. The survey developed will include a request for information on all constituent parts of the solution. From this information we will develop a database of detailed descriptions of system components.

b. Additionally, we will research costs of these elements to determine appropriate OEM costs, from which projections of mark-up can be made.

Task 3 – Written Review of Meter and Meter Component Distributors

The survey and report will include a comprehensive review of facility-based and electronic commerce-based distributors; their customer type and their product offerings. Should the PMRS work with different distributors, each distributor would be contacted to complete the necessary information. The survey will include prices for their offerings.

2.2 Section B – Installation Services

2.2.1 Objectives

The objectives are to review the installation services currently being implemented for solar projects. This will be accomplished through two tasks:

- Task 1 – Identification and Description of Current Installation and Testing Services and Service Providers
- Task 2 – Written Review of Meter Installers and Information Providers

Survey tools will be developed to determine the aspects of PMRS system and meter installation. The end product will include a matrix of the various installation offerings.

2.2.2 Background and Significance

The CEC maintains a listing of “registered retailers” of renewable equipment. The listing includes PV provider, inverter and meter retailers and installers. This listing will identify those installers that have submitted incentive applications. These installers will be contacted to complete the information. From this list source, the installation and commissioning of the field elements of a PMRS will be compiled. This information will identify pertinent providers, applicable certifications and credentials, standards followed and methods used during the installation. Additionally a range of costs will be provided in the report.

2.2.3 Research Design and Methods

As part of the web-based survey, KEMA will solicit information on installers the PMRS providers work with. Utility metering services personnel will also be contacted. A full comparison between PMRS providers, meter installers and information providers and utility practices will be developed in a matrix to outline any commonality and differences.

Task 1 – Identification and Description of Current Installation and Testing Services and Service Providers

This subtask will be completed through surveys of PMRS providers and installers of equipment.

a. The survey will catalog and identify by provider: the type of field testing provided, the tools used to conduct the tests and the installation types provided. This will include any special configurations that may be required to accommodate the meter, current or voltage transformers, safety measures followed, and accuracy verification methods. This would also include tolerances that would be able to be used to determine overall errors that may be anticipated.

b. The survey will catalog the range of costs for installation and commissioning of various system and system types by geographic or other pertinent criteria.

Task 2 – Written Review of Meter Installers and Information Providers

a. KEMA will provide a written review of meter installation firms and qualified electricians who are appropriate for the installation of PMRS systems. This report will provide a listing of their capabilities, certifications, offerings, and delineation of other services offered such as maintenance, warranty repair, emergency services, etc.

2.3 Section D – Performance Monitoring and Reporting Service Providers

2.3.1 Objectives

The objectives are to review the functionality and business offerings of the various PMRS providers. This will be accomplished through three tasks:

- Task 1 – Identification, Description and Evaluation of Existing Product and Service Offerings
- Task 2 – Identification, Description and Evaluation of Long Term Maintenance Offerings
- Task 3 – PMRS Business Evaluation

Survey tools will be developed to determine the aspects of PMRS functionality and business offerings. The end product will include simple block diagrams of the various PMRS systems and a matrix of the various business offerings.

2.3.2 Background and Significance

Thirty-four PMRS providers have been approved as eligible under the CSI. When the CSI started, there were only three providers that had developed metering/data transfer systems targeted for renewable energy customers. Some of the newer PMRS providers have traditionally been general information service providers that have expanded to the renewable energy market. Many vendor-specific systems have been reviewed and there are a number of key differences between systems that should be categorized and evaluated.

2.3.3 Research Design and Methods

As part of the web-based survey, KEMA will solicit enough information to develop simple, high-level block diagrams for the various PMRS providers. The block diagrams will be used to illustrate any commonality and differences between the various services. Business information will also be included, including marketing/distribution channels, business alliances, partnership structures, etc.

Task 1 – Identification, Description and Evaluation of Existing Product and Service Offerings

a. It's very difficult to come up with a comprehensive system diagram that fits all available systems. There is some functional commonality between systems since they all must meet the CSI requirements, but the exact methods of how each PMRS meets those requirements has not be catalogued. System differences will be evaluated as a result of the surveys to be taken. To show the differences, a simple block diagram will be provided for each PMRS that responds to the survey.

Task 2 – Identification, Description and Evaluation of Long Term Maintenance Offerings

a. Long term required maintenance and available warranties from the PMRS providers will be identified as part of the survey.

Task 3 – PMRS Business Evaluation

a. As part of the survey, marketing/distribution channels, business alliances, partnership structures, etc, will be evaluated. Many PMRS systems rely on meters and metering systems from other manufacturers to interface with their data monitoring system.

2.4 Section E – Compare CSI Requirements with Hardware, Labor and Service Offerings

2.4.1 Objectives

The objectives of this task are to quantify, categorize and compare the various hardware, software, and PMRS provider offerings. KEMA will determine how these offerings compare to the CSI requirements; determine system costs and how they relate to the cost caps created for the CSI program. Whether the CSI program has any impacts on these costs and warranties between these systems and typical meter warranties will be determined.

2.4.2 Background and Significance

The eligible "meters" on the CSI listing are quite an eclectic collection. The following basic categories are included:

1) Products from actual meter manufacturers.

2) Products to enable remote viewing for metering devices built in to specific inverters (some manufactured by the inverter manufacturer and some manufactured by others).

3) Products with metering capabilities and with a local display, or a remote display, or that merely provide remote viewing via a computer monitor or the web.

4) Some are kits produced by another party that utilize specific meters and enable remote viewing.

5) Some are meters manufactured by PV manufacturers.

6) Some are systems utilized by PMRS providers.

Overall there's almost 400 meter devices, viewing devices and metering systems on the CSI listing.

The CSI program currently has a 5% and 2% accuracy requirement. The 5% accuracy class is self-reported by the manufacturer. The 2% accuracy class requires 3rd party certification to the accuracy requirements of ANSI C12. These requirements are currently under review by the Metering Subcommittee. The separate task of developing a 5% meter specification is defined in Section I of this Research Plan.

Since the CSI program includes cost caps on PMRS systems, it is unclear whether these caps are too restrictive (limiting the variety of offerings of PMRS systems) or whether a wide variety is available. It is also unclear what impact the CSI program has on PMRS system costs.

2.4.3 Research Design and Methods

KEMA has worked with meter manufacturers to include their products on the CSI listing. KEMA will review the documentation submitted for these products and include a break-down of any certification performed. Also KEMA will identify which PMRS providers use which products that are on the CSI meter list. Meter manufacturers will be contacted as necessary to fill in any gaps in the certification information and to solicit cost information. Since each meter manufacturer on the CSI listing has sent applications to and worked with KEMA to get their products included; there's a familiarity with KEMA in regards to the CSI listing.

The PMRS surveys will include cost and warranty information. Also information on installed systems will be obtained and the number and costs of PMRS systems will be determined. Some PV systems will have PMRS systems installed and some will not (if a PMRS system would exceed the cost cap). Whole systems costs will be determined relative to the cost caps created for the CSI program. From this information conclusions can be made on any limitations or cost drivers the CSI requirements are imposing.

Research

3. AMI Integration with CSI

3.1 Section C – Data transfer

3.1.1 Objectives

KEMA will review the requirements for potential data flows to complete the required integration of various internal and external (to the CSI) systems with the meter data repository including systems those belonging to SCE, and other parties including Administrators for CSI Performance Based Incentive (PBI), and requirements for certifying Renewable Energy Credits (RECs) for the Western Renewable Energy Generation Information System (WREGIS). The specific objectives of the research concerning data transfer are to identify the possible data flows based on the currently available and potential future infra-structures. Besides the identification a comparison will also be made between the potential mechanisms and formats. This comparison will be based on measurable characteristics. Two of the most important ones are service levels and cost, both of which affect total cost of ownership and operations.

3.1.2 Background and Significance

Efficient data transfer mechanisms enable markets of many types around the globe. Data transfer from a technical perspective is simply moving data from one system to another but from a business perspective it allows many different systems, designed for different purposes, to work together. Data transfers allow systems to remain synchronized, reduce the duplication of data, and enable disparate systems to cooperate towards common business goals. Thus, well defined data transfer mechanisms and protocols are a key element for success.

Many markets have used common standards for metering and to enable deregulation and the approach taken will dissect the potential data flows, data formats, and data transfer points and a detailed review will be provided that provides a functional overview of the design, including each of the information flows that are required. All technical interfaces will be described from a functional standpoint and most will likely be supported by the form and content of file-based transfers.

The detailed format of the interfaces associated with the integration of AMI and PV will not be addressed at this time but the required data elements shall be identified and grouped together.

"Not considering organizational or business issues and focusing only on technical aspects may lead to an information and process integration failure."

Research KEMA

- Strategic Architecture: Enabling the Services Integration Framework with the Enterprise Service Bus, Fiammante, Torgersen and Weisser, IBM, 2004

When the data transfers have been identified, using service levels is a good approach for specifying the performance requirements of the AMI/PV data transfers since the service levels of each dataflow can be specified individually depending on the criticality of the data, timeliness to support dependent business processes etc. and the availability requirements of the applications can also be evaluated individually rather than for the system as a whole. For each type of dataflow it is necessary to consider specific measurable characteristics such as availability, throughput, frequency, response time, and data quality since some typical metering requirements will vary for PV data e.g. validation and estimation rules and algorithms.

Furthermore, since billing frequency, units, line items etc. may vary between AMI and PV, the data transfer becomes an integration point that must account for these differences in its support for these different business drivers.

3.1.3 Research Design and Methods

The research of this section will consist of 5 parts. In Figure 3.1 below there is a schematic overview of the parts and how they connect.

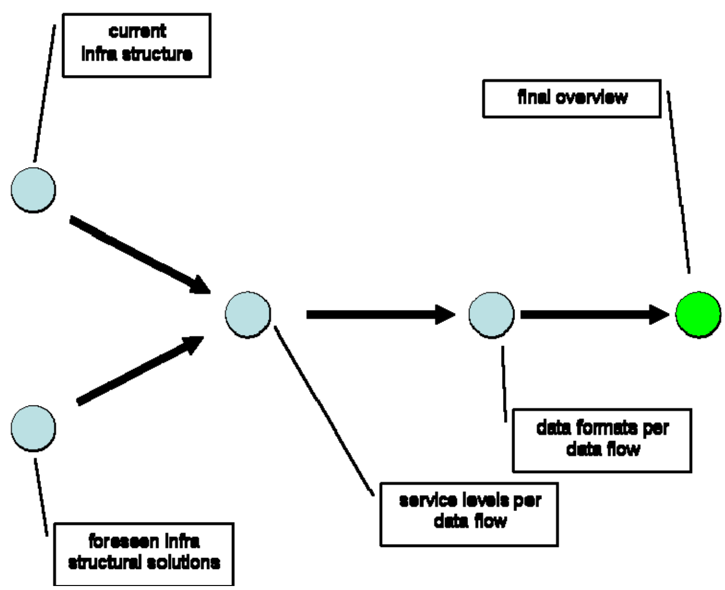


Figure 3-1: Integrating Current and Future Infra-structures

First two parts (stage 1) will be interview/workshop based and preferably will be executed with all involved utilities, although KEMA has utilized email based questionnaires previously to facilitate information gathering from large groups of people and this may be more practical. Based on the current and future states KEMA will identify and dissect potential data flows and applicable service levels for the data flows (stage 2). Ideally these service levels will be discussed with the involved utilities. This is the point at which information will be required relating to business processes and support systems to facilitate support for e.g. multiple billing systems if required.

Applicable data formats per data flow will be identified (stage 3). Finally a cost indication per format (technique) will be added to generate a final overview with potential data flows and technical options (stage 4).

Stage 1

- Gathering input from part A to get current available (certified) material
- Workshop/interviews or email questionnaires with utilities
    - In case of workshops/interviews:1 – 3 max, 2 attending consultants,8 hr max per workshop
    - Identifying current used infrastructure (including current communication, desired information (net metering, PV-metering, heat metering, …)
    - Exchanging ideas on potential future states
- Finalizing current and future state scenarios

Stage 2

- Identification of potential data flows
    - From current and future state
- Performance indicators
    - Identifying service levels using current knowledge and possible web based research
    - Discussing service levels with participating utilities

Stage 3

- Surveying possible appropriate data formats with vendors using data from section A, web based research and surveys. Currently, vendors seeking CSI certification are not required to provide information of data formats or communications protocols.

- Listing possible data forms and formats per data flow

- Pro's and con's of several data forms and formats

Stage 4

- Adding cost indication per data form and data flow

3.2 Section F – Integration of CSI Metering requirements and AMI

3.2.1 Objectives

The specific objective of this part of the research is to identify the best way to integrate the metering data from AMI and Solar systems by utilizing KEMA's extensive background in AMI systems as well as its hands-on experience with the California Solar Initiative to determine the most effective way of merging and integrating these two areas of technology into an efficient system that leverages the best attributes of both and minimizes duplication of effort in areas such as billing, operations and maintenance. This will start by identifying and evaluating the requirements and systems used for AMI and CSI metering.

3.2.2 Background and Significance

Even though different vendors may utilize similar technologies and offer similar capabilities and functionalities, each particular solution is designed to support specific throughput and capacity, depending on the communication technology adopted and the implementation approach chosen by the vendor whether it be for AMI or PV metering. KEMA will use our considerable experience to provide an assessment of how AMI and solar systems could be best integrated through the use of common technologies and/or standardized data transfer requirements.

In conjunction with KEMA's assessment of how AMI and solar systems could be best integrated, KEMA will evaluate how the AMI programs of California's three investor owned electric utilities can be leveraged to support PMRS noting any similarities and differences in approach and how these could affect the integration with PMRS.

The research described above will also consider how the evolution and deployment of AMI may impact the PMRS market particularly with regards to the data collection and performance monitoring overlaps between the two areas including the work performed by IEEE Standards Coordinating Committee 21 on standard 1547.

3.2.3 Research Design and Methods

The research for this part will consist of the following steps:

In part one KEMA will collect the available solutions from certified vendors and based on this information provide an assessment of how AMI and solar systems can best be integrated. The collection of information will be done by using the existing database, available information from section A and C and requests for clarification if this is deemed necessary. The use of a survey is not likely. Other sources of information that will be used are:

- IEEE standards
- AMI standards
- Metering standards from California, Ontario, UK, and other markets as relevant
- PV standards, formal and de-facto
- Business drivers for AMI and PV

In part two the knowledge of part one will be used to assess how current AMI initiatives of the three investor owned electric utilities can be integrated with solar systems. This integration will not solely focus on used techniques, but also on business and human aspects.

Figure 3-2: Incorporating Many Drivers

Integrating metering requirements purely within AMI can prove challenging but the proposed approach is still similar. This requires looking at current integration standards (formal and de-facto) as well as vendor specific technologies and capabilities so that suitable best practice features can be selected for integration while leaving room to support emerging trends. For instance not all vendors offer the same metering capabilities and even those that do support the same business function do so with different codes in the meters and different filed sizes and codes. This requires that a common format be developed to support integration and this will be completed by reviewing current formats, emerging standards and through discussions with technology vendors in the AMI and PV markets.

Research

4. Market Assessment of Solar Metering

4.1 Section G – Compare Metering Requirements to Other Renewable Energy Incentive Programs

4.1.1 Objectives

The objective of this task is to compare and contrast CSI meter requirements with other renewable energy incentive programs with similar structure and intent. The comparison will be limited to those programs which are most relevant to the CSI Program

4.1.2 Background and Significance

Incentive programs with different goals and structures would call for different metering requirements; therefore it is important to identify programs that are similar to CSI for comparison and contrast. The CSI has a budget of $2,167 million over 10 years, and the goal is to reach 1,940 MW of installed solar capacity by 2016. The CSI program distributes incentives via an upfront payment based on system capacity (EPBB), as well as a 5-year incentive based on actual system output (PBI). It is the intent of the program to ensure optimal value for both solar owners and ratepayers, therefore it is important for CSI to have accurate measurement and monitoring of solar energy output. For solar electric generating systems receiving an EPBB incentive, a basic meter with accuracy of ±5 percent is required. For systems receiving PBI payments, an interval data meter with accuracy of ±2 percent is required.

4.1.3 Research Design and Methods

KEMA will identify five to 10 solar or distributed generation (DG) incentive programs that have similar size, structure and intent as the CSI. The type of programs will include capacity-based buydown programs and production-based incentive programs.

KEMA will initially investigate the programs listed in the table below. This list will be modified as research proceeds.

Capacity-based programs

- New Jersey Customer On-site Renewable Energy (CORE)

Production-based programs

- New Jersey Solar Renewable Energy Credits (SRECs)

- Sacramento Municipal Utility District (SMUD) solar programs
- Nevada renewable generations program
- Arizona Solar Partners Program
- New York State Energy Research and Development Agency (NYSERDA) Customer-Sited Program
- Japan Ministry of Economy, Trade and Industry solar subsidies
- US federal renewables production tax credits (PTC)
- Germany Feed-in Tariffs
- United Kingdom OFGEM-regulated programs
- Other national or international Feed-in Tariff or Standard Offer Programs

Metering requirements research

After programs are identified, KEMA will review publicly available information on the programs' metering requirements. KEMA will start with national information from the Database of State Incentives for Renewables and Efficiency (DSIRE), and explore websites of national and international programs. KEMA will leverage expertise from colleagues worldwide who have worked directly with these programs. In some cases, KEMA will contact the managers of these programs to obtain or confirm data gathered from public sources.

The metering requirements data collected will include meter type, accuracy requirement, meter test standards and certification, meter memory and storage, meter communication and data transfer protocols, meter location and data access requirements, and if applicable, treatment of production incentives when only part of the system is eligible.

A data collection form or spreadsheet will be created to ensure the consistency and easy comparison of the data collected.

Research

4.2 Section H – Current Market Drivers and Future Developments

4.2.1 Objectives

Task 1 - Assessment of Market Drivers and Challenges

The object of this task is to provide an assessment the current status of the metering market. The main tasks include an assessment of the following:

- Current market challenges and drivers, specifically the minimum performance monitoring required to providing adequate confidence for potential solar investors to secure their investment.
- Current market price for the identified systems, the fair and acceptable price that the end-user (i.e., system owner/buyer) is willing to incur, and expected future market prices.

Task 2 – Existing Technical Challenges and Emerging Innovations

The objective of this task is to provide an assessment emerging innovations in metering, data collection, and monitoring for the solar industry, with a focus on AMI, energy management systems, and integrated metering load control. The assessment would include a summary of the technical challenges associated with research and development of new products, including all technical issues associated with current technologies. The assessment will include a complete description of any notable current and emerging market practices.

4.2.2 Background and Significance

The metering and monitoring market for solar systems are driven partly by state policies and market needs. States like New Jersey are considering stricter metering and monitoring standards to provide confidence in the Solar Renewable Energy Credits (SREC) market. In California, with the growth of solar financing options such as Power Purchase Agreements, it is important to have a minimum performance monitoring standards to provide adequate confidence in production data to secure their investment.

While it is important to have production data accurately metered and monitored, this needs to be balanced with the additional cost of requiring certain performance monitoring standards. The additional cost might be partially borne by the market players of the value chain and eventually trickle down to the end-user (ie. System owner/buyer). It is important to identify the fair and acceptable price each market player is willing to bear for the added benefit they gain from having better production data.

KEMA understands the California utilities have already made investments in AMI, energy management systems and integrated metering load control. While KEMA wants the CSI to benefit from the latest innovations available, KEMA is cognizant of preserving the investments the California utilities have already made to their infrastructure. These considerations will take into account the plan behind the meter connections such as ZigBee networks.

4.2.3 Research Design and Methods

Task 1 - Assessment of Market Drivers and Challenges

KEMA will develop a survey that assesses the current status of the metering market. The survey will gather price data, as well as information on current market drivers and challenges that are specific to each stakeholder group. A comprehensive list of stakeholders will be developed, including major financial institutions that are active in the solar market, equipment vendors, PMRS providers, installers, system owners, and industry groups such as California Solar Energy Industry Association and Solar Alliance. The survey will be conducted as an internet survey and/or phone interviews.

The survey will specifically gather information on the following:

- The minimum performance monitoring standards needed to provide adequate confidence to securing their solar investments.
- Whether and how the minimum performance standard might affect the metering market
- Current market price and future price trends for the identified system
- Fair and acceptable price the system owner is expected to incur
- Other market drivers and challenges, and how important these factors are relative to each other

Task 2 – Existing Technical Challenges and Emerging Innovations

KEMA will browse industry news for emerging innovations in metering, data collection, and monitoring for the solar industry, with a focus on AMI, energy management systems, and integrated metering load control. KEMA will interview project managers at the California Energy Commission's Public Interest Energy Research Program which funds the development of emerging energy technologies.

This will be supplemented by an industry survey and/or interviews conducted with major meter manufacturers. The survey will gather information on the following:

- Emerging innovations in metering, data collection and monitoring for the solar industry
- Notable current and new market practices
- Technical challenges associated with research and development of new products, including all technical issues associated with current technologies.

To encourage high response rate among vendors who are concerned about sharing information, KEMA will ensure vendors that their responses will be reported in aggregate without attributing any specific comments to a particular vendor.

5. Meter Specification

5.1 Section I – 5% Meter Specification for Inverter-Integrated Meters

5.1.1 Objectives

The objective of this section is to follow up on work already done by the 5% Meter Certification Working Group to develop a specification for inverter-integrated meters than can be used by independent testing labs to test and certify the accuracy and performance of meters used to report outputs from systems receiving CSI incentives under the EPBB program.

5.1.2 Background and Significance

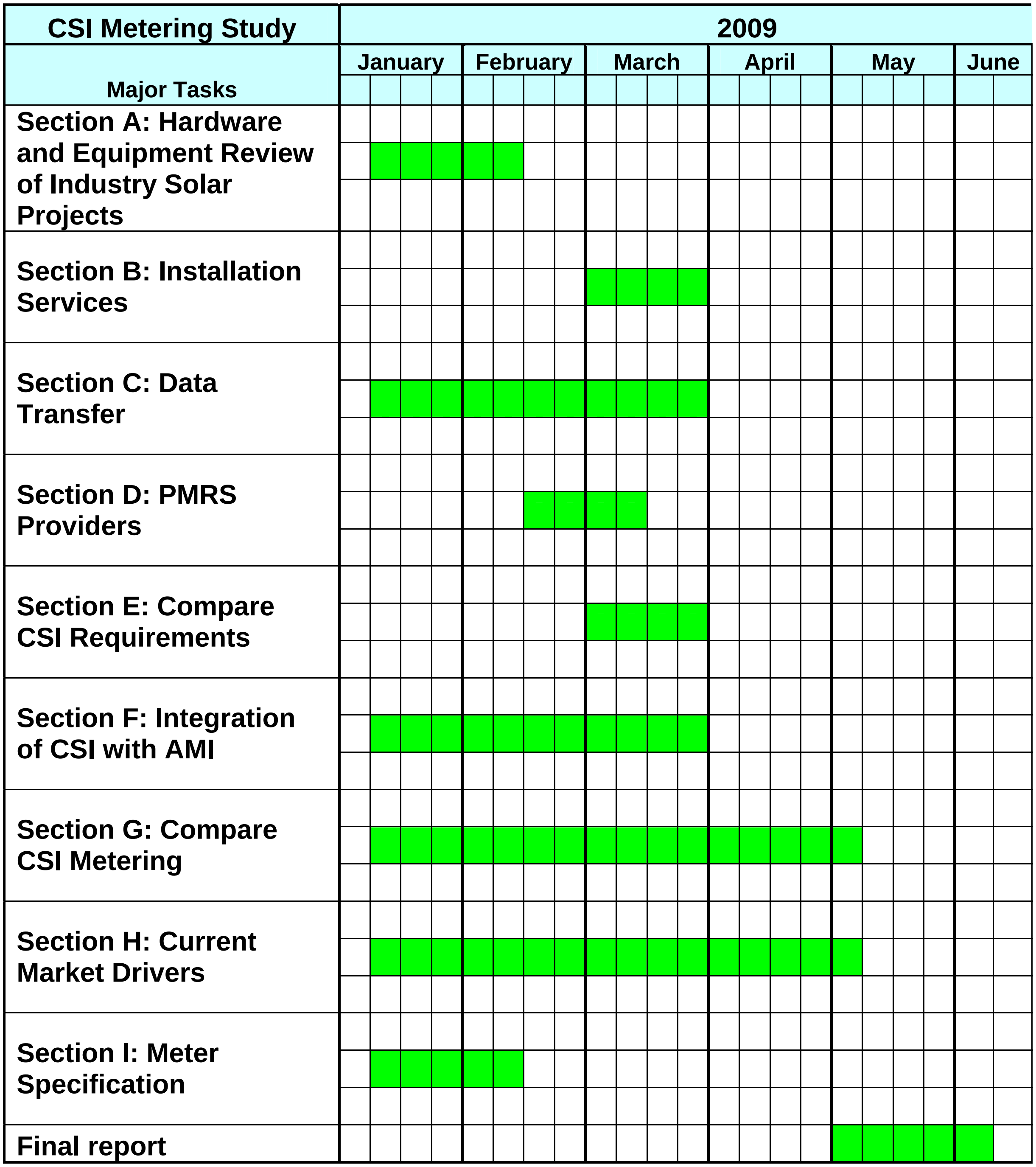
CPUC Decision (D) 06-08-028 required that, “all solar projects that receive incentives through the CSI program shall install a separate solar production meter accurate to within +/- 5% accuracy for systems under 10 KW. This was later modified by (D) 07-07-028 to, “require all systems taking incentives under the EPBB to have meters that are accurate within +/- 5% of the actual system output”.

The CPUC further ordered the Program Administrators (PAs) to, “investigate and develop a plan to ensure the accuracy level of +/- 5% meters used to report output from systems receiving incentives under the EPBB program”.

5.1.3 Research Design and Methods

The research for this section will include the following steps:

- Review of material already produced by the 5% Meter Certification Working Group
- Review of appropriate documentation and specifications produced by ANSI, IEEE, CEC, Underwriters Laboratories and Sandia Labs
- Review of existing specifications and procedures currently in use by major manufacturers, electric utilities and independent testing labs



PRELIMINARY SCHEDULE

Appendix B: 5 Percent Meter Specification

Inverter Integral 5% Meter Performance Specification and Test Requirements

Version: Initial Release

Release Date: 3/25/09

Pete Baumstark, KEMA, Inc., in collaboration with the CSI Metering Subcommittee

Document Revision History

Revision 0	(Original Release)	March 25, 2009
Reserved for future Revisions		(Reserved)

Appendix

1. Overview

Metering devices have been an integral part of DC to AC inverters for many years. Previously, there have been no performance requirements that have been applied to verify accuracy of these metering devices. This purpose of this document is to create those requirements. It draws upon several existing standards and methods to establish inverter metering accuracy requirements.

1.1 Objectives

The objective of this document is to provide a test protocol and performance specification that would be used for verifying inverter integral metering devices to ± 5% accuracy. The test procedures and specifications herein were developed under the assumption that the primary user of this information is either an inverter manufacturer or a Nationally Recognized Test Lab (NRTL) that is recognized by the Occupational Safety and Health Administration (OSHA) as capable of certifying products to UL1741. Many of the tests that are specified in this document can be performed concurrently with UL1741 certification.

Tests specified in this document are either classified as Series or Non-Series. Series tests are to be performed on the same unit whereas Non-Series tests can be performed on other units of the same unique model number. A unique model can pass certification to these requirements by having tests performed on various sample units, and therefore is not required to have all these tests performed on the same unit. Type testing requires each test to be performed on a unique model number. Production testing requires one test to be performed on a sampling of production units. See Appendix A for a listing of test classifications along with a brief over view of the tests.

1.1.1 Approach and Methodology

The following steps (many of which were established by the PV Metering Subcommittee) were used to develop the test requirements presented in this document:

1) Survey of applicable standards relative to meter and inverter certification protocols. These include UL1741, IEEE 1547.1, ANSI C12.1 & the Sandia Inverter Test Protocols.

2) Tabulate ANSI C12.1 tests and determine both applicability for inverter meters and synergies with requirements and intent of UL1741 and IEEE 1547.1 tests. Some test environments defined in ANSI C12.1 are more severe than UL1741 or IEEE 1547.1

environments. In such cases, the UL1741 or IEEE 1547.1 environments were used. Inverter metering systems are only expected to perform under the same environments under which inverters are expected to perform.

3) Obtain industry/technical/certification expert feedback.

4) Perform trial runs of the identified tests at an NRTL's facility and include feedback on feasibility.

5) Write draft requirements for review.

1.1.2 Scope and Purpose

This document provides test requirements for certification of inverter integral metering systems to an accuracy of ± 5%, as measured at the AC output terminals of the inverter or the supplied/required transformer. These requirements are intended to be used in conjunction with certification of inverter products designed for grid-connected PV systems. There is also one test that is designed to be easily performed in conjunction with the California Energy Commission's SB1 eligibility guidelines required weighted efficiency testing (known as Sandia Inverter Test Protocols).

Tests include accuracy verification under a number of typical operational scenarios and abnormal situations that are deemed reasonable based on established certification protocols.

Test protocols are applicable to integrated metering systems, but do not include displays, data logging, data retention or communication devices.

Inverters that have already been certified to UL1741 may have their metering systems certified to ± 5% accuracy per these requirements by submitting samples for testing under these requirements. The long-term purpose of these requirements is to have inverter metering systems certified to ± 5% accuracy in conjunction with UL1741 certification. Every effort has been made to allow appropriate synergies between meter accuracy certification and UL1741 certification.

These tests are intended to supplement UL1741 and are not intended to duplicate or conflict with the UL1741 safety, power quality, utility interconnection, or thermal requirements. Should there be any conflict between UL1741 or IEEE 1547.1 and these requirements, UL1741 and IEEE 1547.1 shall take precedence.

2. Definitions and References

2.1 Definitions

Accuracy: The extent to which a given measurement agrees with the defined value. (from ANSI C12.1-2008)

Calibration: Comparison of the indication of the instrument under test, or registration of the meter under test, with an appropriate standard. (from ANSI C12.1-2008)

Data Acquisition System (DAS): A system that receives data from one or more locations. (from IEEE Std. 100-1996)

Disconnect Switch: A switching device that breaks an electrical circuit. These devices may have AC or DC voltage and current ratings and may or may not be rated for breaking under load. Disconnect switches usually provide a visible break, and may have a locking feature to provide control over the status of the disconnect switch.

Display: A means of visually identifying and presenting measured or calculated quantities and other information. (from ANSI C12.1-2008)

Efficiency: The ratio of the usable AC output power to the total DC + AC input power.

Electric Power System (EPS): (from IEEE Std 1547-2003), Facilities that deliver electric power to a load.

Insolation: A measure of solar radiation energy received on a given surface area in a given time. It is commonly expressed as average irradiance in watts per square meter (W/m^2) or kilowatt-hours per square meter per day ($kW \cdot h/(m^2 \cdot day)$) (or hours/day).

Interconnection: The equipment and procedures necessary to connect an inverter or power generator to the utility grid. IEEE Std. 100-1996 Def: *The physical plant and equipment required to facilitate transfer of electric energy between two or more entities. It can consist of a substation and an associated transmission line and communications facilities or only a simple electric power feeder.*

Inverter: A machine, device, or system that changes direct-current power to alternating-current power. For the purposes of this test procedure, the inverter includes any input conversion (i.e., DC-DC chopper) that is included in the inverter package and any output device (i.e. transformer) that is required for normal operation.

Islanding: Continued operation of a photovoltaic generation facility with local loads after the removal or disconnection of the utility service. This is an unwanted condition that may occur in the rare instance of matched aggregate load and generation within the island.

Inverter Integral Meter: Electricity metering device or system of devices, which measures and registers AC electricity values, and has provisions for a user interface. The entire meter must be physically located within the environmental enclosure of an inverter. For the purpose of this specification, the meter must, at a minimum, be capable of registering cumulative AC energy (watthours). The meter is not required to have a local display.

I-V Curve: A plot of the photovoltaic array current versus voltage characteristic curve. The shape of I-V curve is dependent on the PV cell technology, the configuration of the cells and other devices (e.g., bypass diodes) within the array, varying incident solar irradiance intensity and spectral content, and PV cell temperature.

Listed Equipment: Equipment, components or materials included in a list published by an organization acceptable to the authority having jurisdiction and concerned with product evaluation, that maintains periodic inspection of production of listed equipment or materials, and whose listing states either that the equipment or materials meets appropriate standards or has been tested and found suitable for use in a specified manner. (from the National Electrical Code; Article 100.)

Multi-Phase Units: An inverter which exports power on more than 2 conductors.

Non-islanding: Intended to prevent the continued existence of an island. (from IEEE 1547-2003)

Nationally Recognized Testing Laboratory (NRTL): A listing organization that has passed the Recognition Process by the United States Occupational Safety & Health Administration (OSHA) to certify products to specific standards. A full product certification includes testing of the product to applicable standards and follow-up services, or visits to the manufacturing facility, to ensure consistency of materials and processes that could affect product safety.

Power – Active: The time average of the instantaneous power over one period of the wave. Note: For sinusoidal quantities in a two-wire circuit, it is the product of the voltage, the current , and the cosine of the phase angle between them. For nonsinusoidal quantities, it is the sum of all the harmonic components, each determined as above. In a polyphase circuit, it is the sum of the active power of the individual phases. (from ANSI C12.1-2008)

Power – Apparent: The product of rms current and rms voltage for any wave form in a two-wire circuit. For sinusoidal quantities, apparent power is equal to the square root of the sum of the squares of the active and reactive power in both two-wire and polyphase circuits.

Power – Reactive: For sinusoidal quantities in a two-wire circuit, reactive power is the product of the voltage, the current, and the sine of the phase angle between them, using the current as reference. (from ANSI C12.1-2008)

Reference Meter: An electricity meter used, on the AC side only, as a basis for comparison with inverter integral meter performance under test conditions. For AC energy measurements, reference meters shall be capable of registering energy flow in the positive direction (from the inverter) only.

Simulated Utility: An assembly of voltage and frequency test equipment replicating a utility power source. Where appropriate, the actual Area EPS can be used as the Simulated Utility. (From IEEE P1547.1)

Unit Under Test (UUT): The particular inverter undergoing the specified test.

Utility: For this document, the organization having jurisdiction over the interconnection of the photovoltaic system and with whom the owner may enter into an interconnection agreement. This may be a traditional electric utility, a distribution company, or some other organization. IEEE 100 Def: *An organization responsible for the installation, operation, or maintenance of electric supply or communications systems.*

2.2 References

Principal references used in this document are as follows:

1) UL1741, “Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources”, November 7, 2005

2) ANSI C12.1-2008, “American National Standard for Electric Meters – Code for Electricity Metering”, June 27, 2008

3) IEEE Std 1547.1™-2005, “IEEE Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems”, July 1, 2005

4) “Performance Test Protocol for Evaluating Inverters Used in Grid-Connected Photovoltaic Systems”, Ward Bower, Chuck Whitaker, William Erdman, Michael Behnke, Mark Fitzgerald; October 2004 (This document is sometimes referred to as the Sandia document)

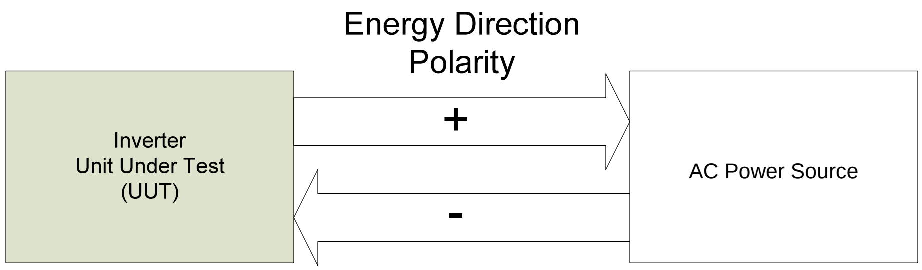
5) IEEE C37.90.1-1989, “IEEE Standard Surge Withstand Capability (SWC) Tests for Protective Relays and Relay Systems”, June 1989

3. Test and Equipment Requirements

3.1 General Requirements

As a standard convention, the power provided by the inverter to the AC power source is considered positive and power supplied by the AC power source to the inverter is considered negative.

Figure 3-1: Energy Direction Polarity



For tests that require a recording of a stabilized operating temperature, temperatures are considered to be stable when three successive readings taken at not less than 15 minute intervals or not more than 10% of the previous elapsed duration following an initial 150 minutes of operation indicates no more than 1°C (1.8 °F) variation between any two readings..

3.2 Test Measurement Requirements

Unless otherwise specified, the requirements in this section apply to all test procedures. Basic measurement equipment uncertainty requirements are provided in Table 3-1..

Table 3-1: Basic Measurement Uncertainty Requirements

Parameter True RMS (V,I,P)	**Allowable Maximum Uncertainty**	**Preferred Maximum Uncertainty**
AC Voltage	± 1% of reading	± 0.25% of reading
AC Current	± 1% of reading	± 0.5% of reading
AC Power*	± 1% of reading	± 0.5% of reading
AC Energy*	± 1% of reading	± 0.5% of reading
AC Frequency	± 0.05 Hz	± 0.01 Hz
Temperature	±1°C	±0.5°C

*Note: AC power and energy measurements should include only the usable 60Hz power.

Though some of the wording of this document may imply a data acquisition system and logging, any suitable equipment or method that provides the necessary functionality and accuracy may be used to perform these tests.

Input voltages and currents are to be measured at the input terminals of the UUT or between the input supply (e.g., PV array) and the connection point of any optional or ancillary equipment external to the UUT. Output voltages and currents are measured at the output terminals of the UUT or at output terminals of the supplied/required external transformer.

Ambient air temperature shall be measured at least 6 inches (15 cm) horizontally away from the UUT enclosure and at the mid-point of the height of the enclosure, and out of the UUT's convection or forced airflow. Ambient air movement will be minimized only to the extent it is necessary to maintain ambient temperature at the specified level. When an environmental chamber is used to control temperature, shrouds or secondary enclosures may be needed to meet this requirement.

Inverter temperature shall be measured internally, at the switching device, or as close as practical.

All test equipment shall be calibrated and traceable to appropriate NIST or other standards.

3.3 Inverter AC Power Supply Requirements

The AC power supply (connected to the AC output of the UUT) may be either a simulated utility or the actual utility. A simulated utility must conform to the requirements defined in IEEE 1547.1, paragraph 4.6.1, Simulated area EPS (utility) source requirements.

3.4 Reference Meter Requirements

Some tests require the use of a reference energy meter to verify the accuracy of the integral metering device of the UUT. Reference energy meters shall be certified to a minimum accuracy of, ± 0.5% of watt-hour production. Reference meter calibration shall be verified prior to any series of tests performed on each UUT.

3.5 Test Set-up Requirements

Each test set-up shall include the configuration the UUT will see in the field (e.g. all faceplates and covers installed, normal position, and all ground terminals wired to ground).

If the UUT has the option of an integral meter display, such a display shall be installed in normal position. It is not necessary to include connections for any remote display device.

3.6 Recording Energy Readings

This specification is intended to verify energy (watt-hour) production accuracy of inverter integral metering devices. For each test that specifies the recording of energy production, the UUT must run for a suitable time period to record watt-hour production. The time period may vary for different UUT model numbers based on the design of its integral metering device.

3.7 Accuracy Performance Check Procedure

Some tests require a periodic Accuracy Performance Check, which would be performed before and after the test. The UUT meter power output shall be read and compared to the energy output reading from a calibrated reference meter. The purpose of the check is to determine whether any detrimental damage occurred to the UUT metering device during specific tests. Where an “Accuracy Performance Check” is specified, the following procedure shall be followed:

a) Install reference meter between UUT output and power source.

b) Connect the UUT according to the instructions and specifications provided by the manufacturer to the selected input and output power sources.

c) Set all input source parameters to the nominal operating conditions for the UUT.

d) Set (or verify) all UUT parameters to the nominal operating settings.

e) Set the UUT (including the input source as necessary) to provide 20% ± 3% of its rated output power.

f) Record all applicable settings.

g) After allowing the inverter output power to stabilize, record energy (watt-hours) from both the inverter meter and the reference meter.

h) Set the UUT (including the input source as necessary) to 100% ± 3% of its rated output power.

i) After allowing the inverter output power to stabilize, record energy (watt-hours) from both the inverter meter and the reference.

j) Power down the input and output sources per manufacturers instructions.

k) Disconnect input and output power sources from the UUT.

l) Perform the specified environmental test.

m) Repeat steps a) through k).

3.7.1 Reporting of Data

For the test, report and calculate pre- and post- environmental test:

- Inverter meter output energy at 20% and 100%
- Reference meter energy at 20% and 100%
- The percent registration for all four cases.

The percent registration is calculated per Equation 3-1.

Equation 3-1: Percent Registration

Percent Registration = 100 x (Ref Meter Energy – Inverter Meter Energy)/Ref Meter Energy

3.7.2 Pass/Fail Criteria

The unit passes if the following two cases are met:

- At 20% output, the absolute difference between Percent Registration pre- and post-environmental test is less than 2.5%.
- At 100% output, the absolute difference between Percent Registration pre- and post-environmental test is less than 2.5%.

3.8 Tests Performed In Series

The following tests shall be conducted using the same inverter: Insulation, Voltage Interruptions from Loss of Control Circuit, Effect of High Voltage Line Surges, Electrical Fast/Transient Burst, Effect of Electrical Oscillatory Surge Withstand Capabilities (SWC) Test, Effect of Electrostatic Discharge (ESD) and Effect of Relative Humidity.

An Accuracy Performance Check per 3.7 is specified to be performed in conjunction with each of these tests per this document. It is permissible to perform the Accuracy Performance Check, at a minimum, pre- and post- the entire block of series tests.

3.9 Weather Survivability

ANSI C12.1 defines several weather survivability tests for metering devices. UL1741 and IEEE 1547.1 also define several weather survivability tests for inverters. These requirements were developed with the assumption that inverter integral metering devices are to survive all environments that inverters are designed and tested to survive. Therefore weather survivability tests in conformance with, or similar to, the ANSI C12.1 tests are not included in these requirements.

4. Specific Test Requirements

4.1 Test No. 1: No Load

This test is intended to ensure the inverter metering device is not registering energy output with the inverter on, power sources and metering circuitry active, but no AC power being generated. The test is performed as a Type test in the lab, and also as a Production test in the manufacturers' facility. The sampling of the production tests to be completed is at the discretion of the manufacturer (not every production unit is required to be tested).

4.1.1 Test No. 1a: No Load

The purpose of this test is to ensure the inverter meter is not registering generation when no load is on the UUT.

a) Adjust the test environment air temperature to 23°C ± 5°C.

b) Connect the UUT according to the instructions and specifications provided by the manufacturer to the selected output power source.

c) Set (or verify) all UUT parameters to the nominal operating settings. Temporary adjustment of UUT grid re-connections timer(s) is allowable for the duration of this test.

d) Set output power source to the UUT's rated voltage +/- 2%.

e) Set input power source to the UUT's nominal operating input voltage +/- 2%.

f) Ensure the UUT is on, with the metering circuitry active, but not producing any AC energy.

g) Record all applicable settings.

h) Measure and record inverter and reference meter energy (kWh) output for a duration of 15 minutes.

4.1.1.1 Reporting of Data

For the test, calculate and report:

- o Inverter and reference meter energy output. The reference meter is used to ensure no actual AC output energy has been produced.

4.1.1.2 Pass/Fail Criteria

The unit passes if the inverter meter reads 0-1% of inverter’s rated energy power output for the 15 minute duration.

4.1.2 Test No. 1b: No Load

The manufacturer is to perform the same test procedure as Test No 1a on a sampling of their production units. The sampling rate is at the discretion of the manufacturer. These tests may be performed at the manufacturing facility.

4.2 Test No. 2: Load Performance

The purpose of this test is to verify the accuracy of the metering device throughout the operating power range of the UUT. The test is designed to be easily run concurrently with Sandia Test "Conversion Efficiency", paragraph 5.5.

Perform per the Sandia Conversion Efficiency test procedure with the following additions/modifications:

1) Install test reference meter between the inverter AC output and the power source.

2) In step 6, record energy (kWh) produced from the inverter meter and the reference meter at the end of each power level. For this test, it's only necessary to record energy production at the end of 10, 20, 30, 50, 75 and 100% power levels.

4.2.1 Reporting of Data

For each power level at each test condition, calculate and report:

- Inverter meter output energy (kWh) at each of the six power levels

- Reference meter energy (kWh) at each of the six power levels

- Meter accuracy levels at each of the six power levels

Determine meter accuracy levels per Equation 4-1:

Equation 4-1 Percent Accuracy

% Accuracy = 100 x (Inverter Meter kWh – Reference Meter kWh) / Reference Meter kWh

Enter the meter accuracy levels in the format shown in Table 4-1.

Table 4-1: Meter Accuracy Levels

Test	V_{dc}	V_{ac}	Inverter DC Input Power Level					
			10%	20%	30%	50%	75%	100%
A	V_{nom}	V_{nom}						
B	V_{max}	V_{nom}						
C	V_{min}	V_{nom}						

Calculate the weighted accuracy of the meter per Equation 4-2 for each test (A, B & C).

Equation 4-2 Weighted Accuracy

$$\eta_{Wtd} = 100 \times (0.04 \times \eta_{10} + 0.05 \times \eta_{20} + 0.12 \times \eta_{30} + 0.21 \times \eta_{50} + 0.53 \times \eta_{75} + 0.05 \times \eta_{100})$$

4.2.2 Pass/Fail Criteria

The UUT passes the test if the weighted accuracy is less than ± 5% for each test (A, B & C).

4.3 Test No. 3: Effect of Variation of Voltage

4.3.1 Purpose

The purpose of this test is to verify the accuracy stability of the metering device, during high and low operating AC voltages, relative to its accuracy at nominal voltage.

This procedure uses the inverter over and under AC voltage trip values determined in IEEE 1547.1, Paragraph 5.2, “Test for response to abnormal voltage conditions” as reference for high and low voltage settings.

For the purpose of this test, Inverter Operating Voltage Range shall be defined as, the difference between the inverter’s high trip voltage less the inverter’s low trip voltage. For example, if a 240 V inverter is tested and its trip values are determined to be 216 V (low) and 260 V (high), the Operating Voltage Range is 44 V (260 – 216 = 44).

a) Connect the inverter according to the instructions and specifications provided by the manufacturer. Include Reference Meter between the UUT AC output and the AC power source.

b) Set all source parameters to the nominal operating conditions for the inverter (e.g. input DC voltage and current is set to the inverter’s nominal specified values).

c) Set (or verify) all inverter parameters to the nominal operating settings. If the AC overvoltage or undervoltage settings are adjustable, set the inverter to the minimum overvoltage and undervoltage settings.

d) Record applicable settings.

e) For single-phase units, adjust voltage to the unit’s nominal value. Initiate a ramp up until the unit voltage is no less than 20% of the high end of the Inverter Operating Voltage Range. For example, if the nominal voltage of the UUT is 240 V, and the high end of the Inverter Operating Voltage is 260 V, and the Operating Voltage Range is 44 V, the UUT voltage must be maintained at 251.2 V to 260 V (8.8 V is 20% of 44 V). For multiphase units, adjust voltage to unit’s nominal value on all phases, and initiate the ramp up on each phase until all are no less than 20% of the high end of the Inverter Operating Voltage Range.

f) After allowing the inverter output power to stabilize, record energy (kWh) from both the inverter meter and the reference meter. This voltage level will be maintained for a sufficient duration to register energy readings from both the inverter meter and reference meter.

g) Initiate a ramp down until the unit voltage is within +/- 10% of the nominal inverter voltage. For multiphase units, ramp down on each phase until all are within +/- 10% of the nominal inverter voltage.

h) After allowing the inverter output power to stabilize, record energy (kWh) from both the inverter meter and the reference meter. This voltage level will be maintained for a sufficient duration to register energy readings from both the inverter meter and reference meter.

i) Initiate a ramp down until the unit voltage is no greater than 20% of the low end of its Inverter Operating Voltage Range. For example, if the nominal voltage of the UUT is 240 V, and the low end of the Inverter Operating Voltage is 216 V, and the Operating Voltage Range is 44 V, the UUT voltage must be maintained at 216 V to 224.8 V (8.8 V is 20% of 44 V). For multiphase units, ramp down on each phase until all are no greater than 20% of the low end of the unit's low trip voltage.

j) After allowing the inverter output power to stabilize, record energy (kWh) from both the inverter meter and the reference meter. This voltage level will be maintained for a sufficient duration to register energy readings from both the inverter meter and reference meter.

k) Initiate a ramp up until the unit voltage is no less than 20% of the high end of its Inverter Operating Voltage Range. For multiphase units, ramp up on each phase until all are no less than 20% of the high end of the unit's Inverter Operating Voltage Range.

l) Repeat steps f) through k) four times, always starting at the high end of, and cycling down to the low end of the Inverter Operating Voltage Range. A total of five readings will be taken at each of the high, mid and low ends of the Inverter Operating Voltage Range.

4.3.2 Reporting of Data

For each of the three voltage levels, calculate and report:

- Inverter meter output energy (average of five sampled values)
- Reference meter energy (average of five sampled values)
- Meter accuracy levels (average of five sampled values)

Determine meter accuracy levels per Equation 4-1.

4.3.3 Pass/Fail Criteria

Accuracies at the high and low voltage settings must be within ±2.5% of the accuracy at the nominal voltage setting. These criteria are further explained in Table 4-2.

Table 4-2: Effect of Variation of Voltage

Voltage Level	Permissible Deviation in Energy Reading From Nominal Voltage Level
Nominal	Reference
High (within 20% of maximum operating voltage)	±2.5%
Low (within 20% of minimum operating voltage)	±2.5%

4.4 Test No. 4: Effect of Variation of Frequency

4.4.1 Purpose

The purpose of this test is to verify the accuracy stability of the metering device during high and low operating frequencies, relative to its accuracy at nominal frequency..

a) Connect the inverter according to the instructions and specifications provided by the manufacturer. Include Reference Meter between the UUT AC output and the AC power source.

b) Set all source parameters to the nominal operating conditions for the inverter (e.g. input DC voltage and current is set to the inverter's nominal specified values).

c) Set (or verify) all inverter parameters to the nominal operating settings. If the overfrequency or underfrequency settings are adjustable, set the inverter to the minimum overfrequency and underfrequency settings.

d) Record applicable settings.

e) Adjust the source frequency to the unit's nominal value. Initiate a ramp up until the unit frequency is within 2x the manufacturers stated accuracy of its maximum operating frequency.

f) After allowing the inverter output power to stabilize, record energy (kWh) from both the inverter meter and the reference meter. This frequency level will be maintained for a sufficient duration to register energy readings from both the inverter meter and reference meter..

g) Initiate a ramp down until the unit frequency is within +/- 1% of its nominal operating frequency (typically 60 Hz).

h) After allowing the inverter output power to stabilize, record energy (kWh) from both the inverter meter and the reference meter. This frequency level will be maintained for a sufficient duration to register energy readings from both the inverter meter and reference meter.

i) Initiate a ramp down until the unit frequency is within 2x the manufacturers stated accuracy of its minimum operating frequency.

j) After allowing the inverter output power to stabilize, record energy (kWh) from both the inverter meter and the reference meter. This frequency level will be maintained for a sufficient duration to register energy readings from both the inverter meter and reference meter.

k) Initiate a ramp up until the unit frequency is within 2x the manufacturers stated accuracy of its maximum operating frequency.

l) Repeat steps f) through k) four times, always starting at the high end of, and cycling down to the low end of the manufacturers operating frequency range. A total of five readings will be taken at each of the high, mid and low ends of the range.

4.4.2 Reporting of Data

For each of the three voltage levels, calculate and report:

- o Inverter meter output energy (average of five sampled values)
- o Reference meter energy (average of five sampled values)
- o Meter accuracy levels (average of five sampled values)

Determine meter accuracy levels per Equation 4-1.

4.4.3 Pass/Fail Criteria

Accuracies at the high and low frequency settings must be within ±2.5% of the accuracy at the nominal frequency setting. These criteria are further explained in Table 4-3.

Table 4-3: Effect of Variation of Frequency

Frequency Level	Permissible Deviation in Energy Reading From Nominal Frequency Level
Nominal	Reference
High (within 20% of maximum operating voltage)	±2.5%
Low (within 20% of minimum operating voltage)	±2.5%

4.5 Test No. 5: Effect of Internal Heating

The purpose of the test is to determine any effects of internal heating on inverter meter accuracy.

a) Adjust the test environment air temperature to 23°C ± 5°C. Allow UUT to stabilize at the set temperature.

b) Connect the UUT according to the instructions and specifications provided by the manufacturer to the selected input and output power sources.

c) Set all input source parameters to the nominal operating conditions for the UUT.

d) Set (or verify) all UUT parameters to the nominal operating settings.

e) Set the UUT (including the input source as necessary) to provide 100% ± 3% of its rated output power.

f) Record all applicable settings.

g) Stage 1: Allow UUT to run at 100% ± 3% rated power for 30 minutes while recording energy (kWh) from the UUT integral meter and the reference meter. Ensure power level from reference meter remains at 100% ± 3% rated power for the duration of the test. Should there be any drift, adjust input source parameters as necessary to keep the UUT operation at 100% ± 3%.

h) Stage 2: Allow UUT to continue to run at 100% ± 3% rated power for another 30 minutes while recording energy (kWh) from the UUT integral meter and the reference meter. Ensure power level from reference meter remains at 100% ± 3% rated power for the duration of the test. Should there be any drift, adjust input source parameters as necessary to keep the UUT operation at 100% ± 3%.

i) Shut down input source per manufacturers recommended procedures for a duration of two hours. UUT will power down and input power source will remain powered.

j) Set the UUT (including the input source as necessary) to provide 20% ± 3% of its rated output power.

k) Record all applicable settings.

l) Stage 3: Allow UUT to run at 20% ± 3% rated power for 30 minutes while recording energy (kWh) from the UUT integral meter and the reference meter. Ensure power level from reference meter remains at 20% ± 3% rated power for the duration of the test. Should there be any drift, adjust input source parameters as necessary to keep the UUT operation at 20% ± 3%.

m) Set the UUT (including the input source as necessary) to provide 100% ± 3% of its rated output power.

n) Record all applicable settings.

o) Stage 4: Allow UUT to run at 100% ± 3% rated power for 30 minutes while recording energy (kWh) from the UUT integral meter and the reference meter. Ensure power level from reference meter remains at 100% ± 3% rated power for the duration of the test. Should there be any drift, adjust input source parameters as necessary to keep the UUT operation at 100% ± 3%.

4.5.1 Reporting of Data

For each stage of the test, calculate and report:

- Inverter meter energy (kWh) output
- Reference meter energy (kWh) output
- Meter accuracy levels

Determine meter accuracy levels per Equation 4-1.

4.5.2 Pass/Fail Criteria

The UUT passes this test if meter accuracy levels are within the following ranges for each test stage:

- Stage 1: ± 2.5%
- Stage 2: ± 3.75%
- Stage 3: ± 2.5%
- Stage 4: ± 2.5%

4.6 Test No. 6: Stability of Performance

The inverter shall be operated continuously. The output shall begin at 10% ± 3% and ramp up in 10% ± 3% increments until 100% ± 3% is achieved. The duration of each operation interval shall be at least 24 hours. The change in percentage of performance at the beginning and end of each power level shall not vary by more than 2.5%.

It is permissible for manufacturers to perform a self-certification to this test requirement.

a) Adjust the test environment air temperature to 23°C ± 5°C.

b) Connect the UUT according to the instructions and specifications provided by the manufacturer to the selected input and output power sources.

c) Set all input source parameters to the nominal operating conditions for the UUT.

d) Set (or verify) all UUT parameters to the nominal operating settings.

e) Set the UUT (including the input source as necessary) to provide 10% ± 3% of its rated output power.

f) Record all applicable settings.

g) Run UUT at this setting for a minimum of 24 hours while recording energy (kWh) from the UUT integral meter and the reference meter. Record energy production at the beginning and end of the interval for a sufficient duration to register energy readings from both the inverter meter and reference meter.

h) Repeat steps e) through g) in steps of 10% of its rated power. Maintain an output tolerance of ± 3% at each interval (e.g. 20% ± 3%, 30% ± 3%, etc). In other words, the tolerance is *not* cumulative (e.g. 20% ± 6%, 30% ± 9%, etc).

i) Entire test shall not exceed two weeks.

4.6.1 Reporting of Data

For each step of the test, calculate and report:

- Inverter meter output energy (kWh) at beginning and end of each power level
- Reference meter energy (kWh) at beginning and end of each power level
- Meter accuracy levels at beginning and end of each power level

Determine meter accuracy levels per Equation 4-1. Tabulate the meter accuracy at the beginning and end of each 10% step of inverter output.

4.6.2 Pass/Fail Criteria

The unit passes the test if inverter meter accuracy does not vary by more than 2.5% between the beginning and end of each 10% step of inverter output.

4.7 Test No. 7: Independence of Elements

The purpose of this test is to ensure the inverter meter is not registering when an output phase is non-functional. This test only applies to multi-phase units (an inverter which exports power on more than two conductors). This test can be performed in conjunction with Test No. 1: No Load.

a) Adjust the test environment air temperature to 23°C ± 5°C.

b) Connect the UUT according to the instructions and specifications provided by the manufacturer to the selected output power source.

c) Set (or verify) all UUT parameters to the nominal operating settings. Temporary adjustment of UUT grid re-connections timer(s) is allowable for the duration of this test.

d) Set output power source to the UUT's rated voltage +/- 2%.

e) Set input power source to the UUT's nominal operating input voltage +/- 2%.

f) Ensure the UUT is on, with the metering circuitry active, but not producing any AC energy.

g) Record all applicable settings.

h) Disconnect one phase from the output circuit. The manufacturer can select any one phase.

i) Measure and record inverter and reference meter energy (kWh) output for a duration of 15 minutes.

4.7.1 Reporting of Data

For the test, calculate and report:

- Inverter and reference meter energy output. The reference meter is used to ensure no actual AC output energy has been produced.

4.7.2 Pass/Fail Criteria

The unit passes if the inverter meter reads 0-1% of inverter's rated energy consumption for the 15 minute duration.

4.8 Test No. 8: Insulation

This test is performed in conjunction with UL1741, Section 44, "Dielectric Voltage-Withstand Test" (also known as the Hypot test).

The purpose of this test is to ensure the inverter meter is still functional after the application of AC rms test potentials as defined in the UL1741 Hypot test.

Perform an Accuracy Performance Check (3.7) in conjunction with the UL1741 Hypot test. Ensure the pre and post measurements are recorded with the UUT at operational temperatures as specified in UL1741, Section 44.

4.9 Test No. 9: Voltage Interruptions

This testing is performed in two parts.

4.9.1 Test No. 9a: Voltage Interruptions from Short Circuits

This test is performed in conjunction with UL1741, Section 47.3, "Short-circuit test"

The purpose of this test is to ensure the inverter meter is still functional after short-circuits on both the AC and DC side of the UUT.

Perform an Accuracy Performance Check (3.7) in conjunction with the UL1741 Short-circuit test.

4.9.2 Test No. 9b: Voltage Interruptions from Loss of Control Circuit

This test is performed in conjunction with UL1741, Section 47.8, "Loss of control circuit"

The purpose of this test is to ensure the inverter meter is still functional after a control circuit loss.

Perform an Accuracy Performance Check (3.7) in conjunction with the UL1741 Loss of control circuit test.

4.10 Test No. 10: Effect of High Voltage Line Surges

This test is performed in conjunction with IEEE 1547.1, Paragraph 5.5.2, “Surge withstand performance test”.

The purpose of this test is to ensure the inverter meter is still functional after a high voltage surge.

Perform an Accuracy Performance Check (3.7) in conjunction with the UL1741 Loss of control circuit test.

4.11 Test No. 11: Effect of Variation of Ambient Temperature

The purpose of the test is to determine any effects of ambient temperature on inverter meter accuracy.

a) Obtain maximum and minimum ambient operating temperatures from manufacturer's specifications.

b) Adjust the test environment air temperature for the reference case to 23°C ± 5°C.

c) Connect the UUT according to the instructions and specifications provided by the manufacturer to the selected output power sources. Input sources are not energized for this test. Include output reference meter in set-up.

d) Set all output source parameters to the nominal operating conditions for the UUT.

e) Set (or verify) all UUT parameters to the nominal operating settings.

f) Record all applicable settings.

g) Allow UUT to stand for not less than two hours to obtain an equilibrium temperature.

h) Connect the UUT according to the instructions and specifications provided by the manufacturer to the selected input power sources.

i) Set all input source parameters to the nominal operating conditions for the UUT.

j) Set (or verify) all UUT parameters to the nominal operating settings.

k) Set the UUT (including the input source as necessary) to provide 20% ± 3% of its rated output power.

l) Record all applicable settings.

m) Stage 1: Allow UUT to run at 20% ± 3% rated power for 60 minutes while recording energy (kWh) from the UUT integral meter and the reference meter. Ensure power level from reference meter remains at 20% ± 3% rated power for the duration of the test. Should there be any drift, adjust input source parameters as necessary to keep the UUT operation at 20% ± 3%.

n) Set the UUT (including the input source as necessary) to provide 50% ± 3% of its rated output power.

o) Record all applicable settings.

p) Stage 2: Allow UUT to run at 50% ± 3% rated power for 60 minutes while recording energy (kWh) from the UUT integral meter and the reference meter. Ensure power level from reference meter remains at 50% ± 3% rated power for the duration of the test. Should there be any drift, adjust input source parameters as necessary to keep the UUT operation at 50% ± 3%.

q) Shut down input source per manufacturers recommended procedure. UUT will power down and output power source will remain powered.

r) Adjust the test environment air temperature within 5°C, but not exceeding the manufacturers' high ambient temperature specification.

s) Record all applicable settings.

t) Allow UUT to stand for not less than two hours to obtain an equilibrium temperature.

u) Set the UUT (including the input source as necessary) to provide 20% ± 3% of its rated output power.

v) Record all applicable settings.

w) Stage 3: Allow UUT to run at 20% ± 3% rated power for 60 minutes while recording energy (kWh) from the UUT integral meter and the reference meter. Ensure power level from reference meter remains at 20% ± 3% rated power for the duration of the test. Should there be any drift, adjust input source parameters as necessary to keep the UUT operation at 20% ± 3%.

x) Set the UUT (including the input source as necessary) to provide 50% ± 3% of its rated output power.

y) Record all applicable settings.

z) Stage 4: Allow UUT to run at 50% ± 3% rated power for 60 minutes while recording energy (kWh) from the UUT integral meter and the reference meter. Ensure power level from reference meter remains at 50% ± 3% rated power for the duration of the test.

Should there be any drift, adjust input source parameters as necessary to keep the UUT operation at 50% ± 3%.

aa) Shut down input source per manufacturers recommended procedures. UUT will power down and output power source will remain powered.

bb) Adjust the test environment air temperature within 5°C, but not below the manufacturers' low ambient temperature specification.

cc) Record all applicable settings.

dd) Allow UUT to stand for not less than two hours to obtain an equilibrium temperature.

ee) Set the UUT (including the input source as necessary) to provide 20% ± 3% of its rated output power.

ff) Record all applicable settings.

gg) Stage 5: Allow UUT to run at 20% ± 3% rated power for 60 minutes while recording energy (kWh) from the UUT integral meter and the reference meter. Ensure power level from reference meter remains at 20% ± 3% rated power for the duration of the test. Should there be any drift, adjust input source parameters as necessary to keep the UUT operation at 20% ± 3%.

hh) Set the UUT (including the input source as necessary) to provide 50% ± 3% of its rated output power.

ii) Record all applicable settings.

jj) Stage 6: Allow UUT to run at 50% ± 3% rated power for 60 minutes while recording energy (kWh) from the UUT integral meter and the reference meter. Ensure power level from reference meter remains at 50% ± 3% rated power for the duration of the test. Should there be any drift, adjust input source parameters as necessary to keep the UUT operation at 50% ± 3%.

kk) Shut down input and output power sources per manufacturers recommended procedures.

4.11.1 Reporting of Data

For each stage of the test, calculate and report:

- Inverter meter output energy (kWh)
- Reference meter energy (kWh)
- Meter accuracy levels

Determine meter accuracy levels per Equation 4-1 and record in format shown in Table 4-4.

Table 4-4: Effect of Variation of Ambient Temperature

Stage	Loading	Ambient Temperature (°C)	Meter Accuracy (%)	Deviation from Stage 1 or 2 (%)
1	20% Power			Reference for Stage 3 & 5
2	50% Power			Reference for Stage 4 & 6
3	20% Power			
4	50% Power			
5	20% Power			
6	50% Power			

4.11.2 Pass/Fail Criteria

The UUT passes this test if the conditions of Table 4-5 are met.

Table 4-5: Effect of Variation of Ambient Temperature Pass/Fail Criteria

Stage	Loading	Ambient Temperature (°C)	Deviation from Stage 1 or 2 (%)
1	20% Power	23 ± 5	Reference for Stage 3 & 5
2	50% Power	23 ± 5	Reference for Stage 4 & 6
3	20% Power	Within 5° of manufacturer max specified temperature	± 2.5
4	50% Power	Within 5° of manufacturer max specified temperature	± 2.5
5	20% Power	Within 5° of manufacturer min specified temperature	± 5
6	50% Power	Within 5° of manufacturer min specified temperature	± 5

4.12 Test No. 12: Electrical Fast/Transient Burst

The purpose of this test is to ensure the inverter meter is still functional after exposure to electrical fast/transient bursts.

Perform electrical fast transient burst testing per IEEE C37.90.1.

Perform an Accuracy Performance Check as specified in this document (3.7).

4.13 Test No. 13: Effect of Electrical Oscillatory Surge Withstand Capabilities (SWC) test

The purpose of this test is to ensure the inverter meter is still functional after exposure to electrical oscillatory surges.

Perform oscillatory SWC testing per IEEE C37.90.1.

Perform an Accuracy Performance Check as specified in this document (3.7).

4.14 Test No. 14: Effect of Radio Frequency Interference

This test is not required if the unit has been certified to FCC Part 15 compliance.

The purpose of this test is to ensure UUT meter functionality after exposure to the Radio Frequency Interference (RFI) environment specified in ANSI C12.1-2008.

Perform test exactly as specified in ANSI C12.1-2008, paragraphs 4.7.3.12 and 4.7.3.12.1, except perform Accuracy Performance Check as specified in this document (3.7).

4.15 Test No. 15: Radio Frequency Conducted and Radiated Emission

This test is not required if the unit has been certified to FCC Part 15 compliance.

The purpose of this test is to ensure UUT meter functionality after exposure to radio frequency conducted and radiated emissions as specified in the Code of Federal Regulations (CFR) 47, Part 15 – Radio Frequency Devices, Subparts A – General and B – Unintentional Radiators issued by the Federal Communications Commission (FCC) for Class “B” digital devices.

Perform test exactly as specified in ANSI C12.1-2008, paragraph 4.7.3.13, except perform Accuracy Performance Check as specified in this document (3.7).

4.16 Test No. 16: Effect of Electrostatic Discharge (ESD)

The purpose of this test is to ensure the inverter meter is still functional after exposure to ESD.

Perform the ESD test as specified in ANSI C12.1, section 4.7.3.14, “Test No. 28: Effect of electrostatic discharge (ESD).

Perform an Accuracy Performance Check as specified in this document (3.7).

4.17 Test No. 17: Effect of Operating Temperature

The purpose of the test is to determine any effects of storage temperature on inverter meter accuracy.

Perform test per IEEE 1547.1, paragraph 5.1.2.2, “Storage temperature test procedure”.

Perform an Accuracy Performance Check as specified in this document (3.7).

4.18 Test No. 18: Effect of Relative Humidity

The purpose of this test is to ensure UUT meter functionality after exposure to the Relative Humidity test environment specified in UL991.

Perform a Relative Humidity test in accordance with the methods described in the Standard for Test for Safety-Related Controls Employing Solid-State Devices, UL991. The exposure class to be used is H5.

Perform an Accuracy Performance Check as specified in this document (3.7).

Appendix A

Table A-1: Inverter Meter Test Summary

Test No.	Title	Purpose of Test	Pass/Fail Criteria	ANSI C12.1 Equivalent Test No.	Series (Y/N)	Type or Production Test (T/P)
1	No Load	Ensure meter is not registering when no load is on the DC input	0 ± 1% of UUT rated output	1	N	T,P
2	Load Performance	Ensure meter accuracy across the insolation spectrum quantified in the Sandia weighted efficiency test procedure (DC inputs of 10, 20, 30, 50, 75 & 100% of unit rating)	± 5% weighted accuracy across spectrum	3	N	P
3	Effect of Variation of Voltage	Verify meter accuracy during high, low and medium AC operating voltages	High and low within ± 2.5% of nominal	5	N	P
4	Effect of Variation of Frequency	Verify meter accuracy during high, low and medium operating frequencies	High and low within ± 2.5% of nominal	6	N	P
5	Effect of Internal Heating	Determine any effects of internal heating on meter accuracy	± 2.5% @ 20% & 100% output power for 30 minutes; ± 3.75% @ 100% output power for 60 minutes	11	N	P
6	Stability of Performance	Ensure meter accuracy between successive output power levels (10, 20, 30, 40, 50, 60, 70, 80, 90, 100%)	± 2.5% between beginning and end of each power level	13	N	P
7	Independence of Elements	Ensure meter is not registering when one output phase is non-functional	0 ± 1% of UUT rated output	14	N	P

Appendix A

Test No.	Title	Purpose of Test	Pass/Fail Criteria	ANSI C12.1 Equivalent Test No.	Series (Y/N)	Type or Production Test (T/P)
8	Insulation	Ensure meter accuracy after UL1741 Hypot test	± 2.5% at both 20 and 100% power levels	15	Y	P
9a	Voltage Interruptions from Short Circuits	Ensure meter accuracy after UL1741 Short-circuit test	± 2.5% at both 20 and 100% power levels	16	Y	P
9b	Voltage Interruptions from Loss of Control Circuit	Ensure meter accuracy after UL1741 Loss of control circuit test	± 2.5% at both 20 and 100% power levels	16	Y	P
10	Effect of High Voltage Line Surges	Ensure meter accuracy after IEEE 1547.1 Surge withstand performance test	± 2.5% at both 20 and 100% power levels	17	Y	P
11	Effect of Variation of Ambient Temperature	Determine effects of ambient temperature on meter accuracy	± 2.5% @ max temp; ± 5% @ min temp	19	N	P
12	Electrical Fast/Transient Burst	Determine protection of metering device from IEC 61000-4-4 Fast Transient Surge Test	± 2.5% @ 20 and 100% rated power output between pre and post test	25	Y	P

Appendix A

Test No.	Title	Purpose of Test	Pass/Fail Criteria	ANSI C12.1 Equivalent Test No.	Series (Y/N)	Type or Production Test (T/P)
13	Effect of electrical oscillatory Surge Withstand Capabilities (SWC) test	Determine protection of metering device from IEEE 37.90.1 Electrical Oscillatory Surge Withstand Capabilities (SWC) test	± 2.5% @ 20 and 100% rated power output between pre and post test	25a	Y	P
14	Effect of Radio Frequency Interference	Determine protection of metering device from ANSI C12.1-2008 Radio Frequency Interference (RFI) environment test	± 2.5% @ 20 and 100% rated power output between pre and post test	26	N	P
15	Radio Frequency Conducted and Radiated Emission	Determine protection of metering device from CFR 47, Part 15 – Radio Frequency Devices, Subparts A & B	± 2.5% @ 20 and 100% rated power output between pre and post test	27	N	P
16	Effect of Electrostatic Discharge (ESD)	Determine protection of metering device from electrostatic discharge (ESD)	± 2.5% @ 20 and 100% rated power output between pre and post test	28	Y	P
17	Effect of Operating Temperature	Determine effects of operating temperature on meter accuracy	± 2.5% @ 20 and 100% rated power output between pre and post test	30	Y	P

Appendix A

Test No.	Title	Purpose of Test	Pass/Fail Criteria	ANSI C12.1 Equivalent Test No.	Series (Y/N)	Type or Production Test (T/P)
18	Effect of Relative Humidity	Ensure meter accuracy after exposure to relative humidity environment of UL991 class H5	± 2.5% @ 20 and 100% rated power output between pre and post test	31	Y	P

Appendix B

Table B-1: Equations Summary

Equation ID	Standard Section ID	Equation
Equation 3-1 Percent Registration	3.7 Accuracy Performance Check Procedure	Percent Registration = 100 x (Ref Meter Energy – Inverter Meter Energy)/Ref Meter Energy
Equation 4-1 Percent Accuracy	4.2 Test No. 2: Load Performance	% Accuracy = 100 x (Inverter Meter kWh – Reference Meter kWh) / Reference Meter kWh
Equation 4-3 Weighted Accuracy	4.2 Test No. 2: Load Performance	$\eta_{Wtd} = 100 \times (0.04 \times \eta_{10} + 0.05 \times \eta_{20} + 0.12 \times \eta_{30} + 0.21 \times \eta_{50} + 0.53 \times \eta_{75} + 0.05 \times \eta_{100})$

Appendix C: PMRS/PDP Existing CSI Products and Services Survey Questions

CSI Meter Survey

1. Introduction

California Solar Initiative (CSI) Metering, Monitoring and Reporting Study

This survey is at the direction of the California Public Utilities Commission with the purpose of assessing the metering, monitoring, and reporting market for Photovoltaic (PV) in California.

To take the survey, perform the following:

1. Enter your company information below, then click Next to begin the survey. The survey should take approximately 30 minutes to complete. If necessary, you can exit and return to the survey and your previous work will be saved.
2. E-mail simple block diagrams of your systems and any pictures of product offerings (or sales brochures if they show pictures) to Pete Baumstark.

If you have any questions, contact info is provided below:

Pete Baumstark, PE
KEMA Services, Inc.
492 Ninth Street
Suite 220
Oakland, CA 94607
T (510) 891-0446, x-4111
pete.baumstark@us.kema.com

*** 1. Please provide us with your contact information.**

Name:

Company:

Email Address:

Phone Number:

CSI Meter Survey

2. Program Overview

*** 1. Give an overview of your product offerings as applicable to the California Solar Initiative (CSI) Performance Monitoring and Reporting Service (PMRS) and Performance Data Provider (PDP) services (if applicable).**

*** 2. When interfacing with a PV system, what type of metering device do you read?**

- Inverter integral meter
- Meter you supply
- Other (please specify)

CSI Meter Survey

3. Component Information

Next we will collect information on the major components required for your system (e.g. communication devices, meters, software, servers).

* 1. Do you have a major component to list?

- ◯ Yes
- ◯ No

CSI Meter Survey

4. Component 1

1. Give a brief description of the component and make / model number.

2. For the component listed above, please provide the following information:

Testing and certification requirements

Warranties provided (both standard and extended)

Required maintenance

*** 3. Do you have another major component to list?**

- Yes
- No

CSI Meter Survey

5. Component 2

1. Give a brief description of the component and make / model number.

2. For the component listed above, please provide the following information:

Testing and certification requirements

Warranties provided (both standard and extended)

Required maintenance

*** 3. Do you have another major component to list?**

- Yes
- No

CSI Meter Survey

6. Component 3

1. Give a brief description of the component and make / model number.

2. For the component listed above, please provide the following information:

Testing and certification requirements

Warranties provided (both standard and extended)

Required maintenance

*** 3. Do you have another major component to list?**

- Yes
- No

CSI Meter Survey

7. Component 4

1. Give a brief description of the component and make / model number.

2. For the component listed above, please provide the following information:

Testing and certification requirements

Warranties provided (both standard and extended)

Required maintenance

*** 3. Do you have another major component to list?**

- Yes
- No

CSI Meter Survey

8. Component 5

1. Give a brief description of the component and make / model number.

2. For the component listed above, please provide the following information:

Testing and certification requirements

Warranties provided (both standard and extended)

Required maintenance

* 3. Do you have another major component to list?

- Yes
- No

CSI Meter Survey

9. Component 6

1. Give a brief description of the component and make / model number.

2. For the component listed above, please provide the following information:

Testing and certification requirements

Warranties provided (both standard and extended)

Required maintenance

CSI Meter Survey

10. Cost Information

Next we will collect information on the cost of your system fully installed. We understand there may be several options and product offerings.

*** 1. Do you have a product offering/service to list?**

- ◯ Yes
- ◯ No

CSI Meter Survey

11. Cost 1

1. Give a brief description and model number of the product offering / system.

2. For the product offering / system listed above:

What is hardware/software cost?

What is the installation/commissioning cost?

What is the annual fee for service?

3. Provide any other associated system costs.

*** 4. Do you have any additional product offering / services to list?**

- Yes
- No

CSI Meter Survey

12. Cost 2

1. Give a brief description and model number of the product offering / system.

2. For the product offering / system listed above:

What is hardware/software cost?

What is the installation/commissioning cost?

What is the annual fee for service?

3. Provide any other associated system costs.

*** 4. Do you have any additional product offering / services to list?**

- Yes
- No

CSI Meter Survey

13. Cost 3

1. Give a brief description and model number of the product offering / system.

2. For the product offering / system listed above:

What is hardware/software cost?

What is the installation/commissioning cost?

What is the annual fee for service?

3. Provide any other associated system costs.

* 4. Do you have any additional product offering / services to list?

- Yes
- No

CSI Meter Survey

14. Cost 4

1. Give a brief description and model number of the product offering / system.

2. For the product offering / system listed above:

What is hardware/software cost?

What is the installation/commissioning cost?

What is the annual fee for service?

3. Provide any other associated system costs.

*** 4. Do you have any additional product offering / services to list?**

- ◯ Yes
- ◯ No

CSI Meter Survey

15. Cost 5

1. Give a brief description and model number of the product offering / system.

2. For the product offering / system listed above:

What is hardware/software cost?

What is the installation/commissioning cost?

What is the annual fee for service?

3. Provide any other associated system costs.

*** 4. Do you have any additional product offering / services to list?**

- ◯ Yes
- ◯ No

CSI Meter Survey

16. Cost 6

1. Give a brief description and model number of the product offering / system.

2. For the product offering / system listed above:

What is hardware/software cost?

What is the installation/commissioning cost?

What is the annual fee for service?

3. Provide any other associated system costs.

CSI Meter Survey

17. Interconnection Methods

1. What interconnection methods do you use?

*** 2. Do you use a Wireless or Hard-Wired communication network to transfer data?**

- Wireless
- Hard-Wired

CSI Meter Survey

18. Wireless

1. What type of Wireless network do you use?

- ◯ Cellular
- ◯ WiFi
- ◯ WiMax
- ◯ Other (please specify)

CSI Meter Survey

19. Hard-Wired

1. What type of Hard-Wired network do you use?

- ◯ Broadband
- ◯ Ethernet
- ◯ Telephone
- ◯ Other (please specify)

CSI Meter Survey

20. Standards

1. Provide a listing of any registered retailers and installers you utilize for your systems.

2. What certifications/credentials are required to install your system?

3. What standards must an installer comply with when installing your system?

4. Give a description of any field testing, commissioning, calibration or accuracy verification of components/systems that are required when installing your system. Please include the following:

- Types of tools are required to conduct these tests.
- Acceptable tolerances used during field verification of your system.
- Standards used for testing calibration

CSI Meter Survey

21. Installation and Maintenance Practices

Next we will collect information on your typical installation and maintenance practices.

1. Please describe your troubleshooting and customer support procedures (and associated costs).

2. Please describe your software and firmware upgrade procedures (and associated costs).

3. Please describe your warranty offerings, including long term required maintenance and available warranties (and associated costs).

4. Please describe your service guarantees (and associated costs).

5. Please provide any other installation and maintenance practices not listed above (and associated costs).

6. Please describe any other services offered (e.g. warranty repair, emergency services, service calls etc.) and any costs associated with those services.

CSI Meter Survey

22. Business Offerings

1. Please describe your business offerings, including the following:
• Marketing / distribution channels
• Business alliances
• Partnership structures
• Examples include partnerships / alliances with meter and inverter manufacturers and electrical / control system contractors.

2. Please describe other services provided to customers, for example:
• Performance data evaluation
• Performance benchmarking
• Customer energy consumption monitoring
• Weather and irradiance monitoring
• System alerting
• Error reporting

CSI Meter Survey

23. Data Collection

1. Provide a listing of all data that is recorded and displayed in your system for PBI and / or EPBB requirements (e.g. monthly kWh, peak kW, interval data, solar irradiance, wind speed etc).

2. How and where is the data stored?

3. What is the minimum frequency data is read and recorded (stored). For example: data read every one minute with an average recorded in 15 minute intervals.

4. What is the duration of data retention (how many days or years is it stored)?

5. Describe your data back-up capability in the event of a power outage or equipment failure.

6. How is data transferred to the utility Program Administrator?

CSI Meter Survey

24. Closing

1. How many systems have you installed since the inception of the CSI program?

Number of systems:

How many for PBI?

How many for EPBB?

2. Do you feel that the cost caps are restrictive in the implementation of PMRS systems?

- Yes
- No

3. If you feel that the cost caps are restrictive, can you give a percent of system costs that would more appropriate?

CSI Meter Survey

25. Thank you

Thank you for completing our survey!

Reminder:
Please e-mail simple block diagrams of your systems and any pictures of product offerings (or sales brochures if they show pictures) to:
Pete Baumstark

Appendix D: EDI 867 Overview

EDI 867

EDI is the exchange of data in a standardized format between computers of two parties. By using standard formats and languages, the data can be transferred from one computer to another and interpreted automatically. Two parties (PMRS/PDP) and Program Administrators (PA – utilities) are known as trading partners and agree to undertake several steps to automate the process of exchanging meter data. The 867 transaction set (EDI 867) is used to transfer meter usage data from PDP to the PA.

The process to initiate the EDI 867 with the PA is specific to each utility and the PMRS/PDP must contact each of them to initiate the process. Data requirements, formats, and other details are provided in the CSI Handbook.

After some computer manipulation at the receiving end, data will appear as shown in the following table.

Sample of PMRS/PDP data stream through EDI is as following:

Engineering Units Report For Excess Channel 02/04/09 16:00

Span: 01/01/09 00:15 To 02/01/09 000:0

	01/01/09 Thu	01/02/09 Fri	01/03/09 Sat	01/04/09 Sun	01/05/09 Mon	01/06/09 Tue
07:30	0.0000	0.0000	0.0000	0.0000	0.0002	0.0000
07:45	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
08:00	0.0000	0.1687	0.0000	0.3715	0.5876	0.0000
08:15	0.0381	0.2467	0.0000	1.5629	2.1215	0.4252
08:30	0.2796	0.6407	0.0280	2.3202	2.9364	1.0400
08:45	0.7836	1.6200	0.2857	3.7931	4.8560	1.3552
09:00	1.5727	2.3803	1.0342	6.2603	6.2800	2.4158
09:15	1.7228	3.0706	0.7628	11.4137	6.1339	1.0117
09:30	1.9654	3.0733	0.9856	13.2813	9.1317	2.9917
09:45	2.5311	3.5651	2.3240	13.8169	12.1162	2.7145
10:00	3.2048	5.2423	4.3274	13.7940	22.7724	3.7401
10:15	4.3425	5.8694	5.2495	14.3930	15.2717	4.1483
10:30	3.9960	6.3810	6.9398	13.1457	12.0159	3.8993
10:45	6.2171	5.7937	7.4657	13.5799	17.8881	2.6755
11:00	5.3535	6.5684	7.0080	19.6969	19.1779	2.8218

11:15	5.1605	8.6719	6.4655	18.8086	14.7529	4.5551
11:30	5.0630	10.0805	7.5454	13.6802	20.4859	4.0923
11:45	7.2091	7.9110	9.8583	13.4134	22.1124	6.6319

Engineering Units Report For Excess Channel 02/04/09 16:00

Span: 01/01/09 00:15 To 02/01/09 000:0

	01/01/09 Thu	01/02/09 Fri	01/03/09 Sat	01/04/09 Sun	01/05/09 Mon	01/06/09 Tue
12:00	7.0864	8.7128	17.3473	14.1548	16.8752	7.1647
12:15	5.8265	9.6477	25.4297	12.2366	12.8267	5.8133
12:30	5.5294	8.9856	34.1017	10.9106	11.2185	6.9616
12:45	5.2814	10.4491	22.0447	14.3073	13.2970	7.8121
13:00	4.8273	11.2538	11.5321	19.0503	18.8673	4.9555
13:15	4.8464	13.0011	16.8052	19.9860	16.7618	5.4475
13:30	4.5582	25.3800	25.4728	22.7666	15.3691	4.3230
13:45	4.2331	24.5866	26.2492	18.4602	11.9246	5.0742
14:00	3.7489	27.9872	28.4923	15.3499	6.9654	4.4158
14:15	3.7291	36.3563	33.5952	8.9110	9.3280	2.9178
14:30	3.2598	39.0277	40.5629	10.0939	7.9932	3.0553
14:45	3.1308	26.0089	29.3815	10.3986	8.3633	2.4933
15:00	2.8732	13.1130	12.9899	10.7522	5.6518	2.5925
15:15	2.1106	7.7200	10.4858	11.2305	4.3127	4.1355
15:30	1.2288	7.5842	7.2818	9.1354	4.8069	4.4845
15:45	0.5543	6.2680	3.9676	6.7253	4.5947	4.5437
16:00	0.1734	2.1211	3.1834	8.2711	4.1826	3.5450
16:15	0.0001	0.7916	1.7773	2.6454	1.5928	2.0610
16:30	0.0000	0.0094	0.8367	1.0994	0.4598	1.0254
16:45	0.0000	0.0000	0.1871	0.1420	0.0505	0.0869

Appendix E WREGIS Classes of Generating Units

WREGIS classifies Generating Units according to their size, contracts and whether the generation is reported to a Balancing Authority on a unit-specific basis.

Table 4: WREGIS GENERATING UNIT CLASSIFICATIONS

Generating Unit Capacity and Existing Contract Determinants	WREGIS Generating Unit Classification			
	Generation Reported to a Balancing Authority on a Unit-Specific Basis	Generation Not Reported to a Balancing Authority on a Unit-Specific Basis		
		Wholesale Generation	Wholesale Generation Also Serving On-Site Load	"Customer-Sited Distributed Generation"
No Determinants - Classification applies to any Generating Unit whose generation is reported to or through a Balancing Authority on a Unit-Specific basis	Class A			
Nameplate capacity greater than 125 kW		Class B		
Nameplate capacity less than or equal to 125 kW where there is no pre-existing contract with the interconnecting utility that allows meter reading and reporting less frequently than monthly		Class C		
Nameplate capacity less than or equal to 125 kW where a pre-existing contract with the interconnecting utility allows meter reading and reporting less frequently than monthly		Class D		

Generating Unit Capacity and Existing Contract Determinants	WREGIS Generating Unit Classification			
	Generation Reported to a Balancing Authority on a Unit-Specific Basis	Generation Not Reported to a Balancing Authority on a Unit-Specific Basis		
		Wholesale Generation	Wholesale Generation Also Serving On-Site Load	"Customer-Sited Distributed Generation"
Nameplate capacity greater than 125 kW				
Nameplate capacity less than or equal to 125 kW where there is no pre-existing contract with the interconnecting utility that allows meter reading and reporting less frequently than monthly			Class F	
Nameplate capacity less than or equal to 125 kW where a pre-existing contract with the interconnecting utility allows meter reading and reporting less frequently than monthly			Class G	
Nameplate capacity greater than 360 kW				Class H
Nameplate capacity less than or equal to 360 kW and with an annual production technically capable of exceeding 30 MWh per year				Class I
Nameplate capacity less than or equal to 360 kW and with an annual production technically not capable of exceeding 30 MWh per year				Class J

Appendix F: Market Research Surveys

CSI Metering Market Survey – Installer/Contractors

Interviewer:
Interviewee Name:
Interviewee Company:
Interviewee Title:
Date:
Time:

Hello. My name is _______________ from KEMA Consulting. I am calling on behalf of the California Public Utilities Commission regarding a comprehensive metering and monitoring study we're conducting under the California Solar Initiative.

I have some questions for your company related to the metering market trends, eg. market drivers, barriers, demand, prices, and emerging technologies.

Are you the right person to speak to? [If no, ask for a referral and record his/her name and contact information: ____]

↳ [If hesitant] We understand that you are busy. However, this research is important to the industry and California's solar policies going forward.

For all the participants of this survey, we will send you a summary of our findings at the conclusion of this research.

If you wish, we can report all or part of the information you give us anonymously or in aggregate with other company's data.

[When agreed to participate] Great! This will take about 30 minutes.

[If not available now, schedule a time to talk within the same week _______________]

I. COMPANY INFORMATION

Before I go into market trends, I'd like to ask you some background questions about your company. Again, please tell me if you want part or all of your response be kept confidential.

1. Approximately how many systems do you install per year total and in CA?

2. How would you characterize your customers in CA?

Sector	% Revenue	PPA (%)	PMRS (%)
Large commercial			
Gov't			
Industrial			

3. How does this characterization different than your customers nationwide?

4. How is a PMRS provider chosen? Do you normally partner with 1-2 PMRS providers? Or do your customers chose the PMRS provider separately?

II. MARKET DRIVERS AND BARRIERS

For the next part, I'd like to ask you some questions about market drivers and barriers.

5. What are the main reasons for your customers to purchase a PMRS? (check all that applies)
    - o Internal use -- optimize performance for energy management for *single* site _____%
    - o Internal use -- optimize performance for energy management for *multiple* site _____%
    - o PPA requirement _____%
    - o Installer/contractor maintenance and support contract _____%
    - o Required by the CSI _____%
    - o Other reasons? ______________

6. How does the CSI affect the usage of PMRS? (check all that applies)
    - o Create a market by requiring PMRS for large systems
    - o Should remove PMRS requirements for systems below ____ kW
    - o CSI cost cap needs to be higher/lower, by how much? ______
    - o Others: ____________________

7. Will you continue to use PMRS after the CSI expires in 2017?

III. Customer Current Demand

For the customers who are using PMRS…

8. In general, what are some features your customers are looking for? And what percentage of your customers looks for them? Do you recommend them?

Features	Customers must have (%)	Nice to have (%)	Recommendation
Minimum meter accuracy ____________________			
DC monitoring			
Performance benchmark			
Weather monitoring			
Multi-site monitoring			
Automated alerts by email or SMS (Customizable by user?)			
Communicate with HAN/BAS/EMS			
Communicate with smart meters			
User-friendly interface			

9. Specifically for the solar investors (eg. PPA), what are the minimum performance monitoring requirements?

Features	Must have (%)	Nice to have (%)
Minimum meter accuracy ______		
DC monitoring		
Performance benchmark		
Weather monitoring		
Multi-site monitoring		

Automated alerts by email or SMS (Customizable by user?)		
Communicate with HAN/BAS/EMS		
Communicate with smart meters		
User-friendly interface		

10. How does a minimum performance standard might affect the metering market?

11. How do these requirements affect the current price? And the price trends? (eg. will these requirements drive the costs down?)

IV. SYSTEMS COSTS AND TRENDS (if familiar)

We're almost done. In the next part, I have a few questions on system costs.

12. What is the cost of a typical PMRS system? (Record range if appropriate)

- Hardware
  - Meter
  - Communications
  - Weather station
- Software
- Installation
- Annual service fee

13. What are the cost trends are you seeing in PMRS?

Costs	Change in 1 year	Change in 3 years
Meter	%	%
Communications	%	%
Weather monitoring	%	%
Software	%	%
Installation	%	%
Annual service fee	%	%

14. What do you think is a reasonable price for PMRS to be? Eg. in terms of % of total system cost.

15. In light of the recent federal stimulus bill, will you or your customers be able to take advantage of it? How?

V. TECHNOLOGICAL TRENDS (if familiar)

16. What are the technological trends are you seeing in PMRS? (eg. meter accuracy, communication systems, user interface etc)

17. What are the emerging innovations in PMRS? (integration with smart grid, EMS etc)

18. What are the main barriers in technological R&D?

19. Do you see that solar's integration with smart grid will be an important R&D area in the near future?

20. What are the barriers for integrating DG solar into smart grids?

21. Do you think solar will be fully integrated into smart grid in the near future? How long do you think it'll take?

VI. CLOSING

That's all the questions I have. Do you have any additional comments or questions?

To ensure the thoroughness of this research, who else would you recommend me to speak to? Can we contact some of your customers? [Ask for customer contact name, phone and email]

I really appreciate your time today. If you think of any additional comments to give me or have questions about this study, please don't hesitate to contact me.

CSI Metering Market Survey – PMRS Providers

Interviewer:
Interviewee Name:
Interviewee Company:
Interviewee Title:
Date:
Time:

Hello. My name is ________________ from KEMA Consulting. I am calling on behalf of the California Public Utilities Commission regarding the California Solar Initiative metering study. Thank you for filling out our product survey earlier this month.

I am calling because we have some market-related questions that are easier to ask you on the phone than through an online survey. These questions are mostly related to the metering market trends, eg. market drivers, barriers, demand, prices, and emerging technologies.

Are you the right person to speak to? [If no, ask for a referral and record his/her name and contact information: ____]

↳ [If hesitant] We understand that you are busy. However, this research is important to the industry and California's solar policies going forward.

For all the participants of this survey, we will send you a summary of our findings at the conclusion of this research.

If you wish, we can report all or part of the information you give us anonymously or in aggregate with other company's data.

[When agreed to participate] Great! This will take about 30 minutes.

[If not available now, schedule a time to talk within the same week _______________]

VII. COMPANY INFORMATION

Before I go into market trends, I'd like to ask you some background questions about your company. Again, please tell me if you want part or all of your response be kept confidential.

1. Is PMRS one of your company's core products? What are your company's other core products? [Try to answer this through the company's web site before calling]

2. Are there any synergies between PMRS and your other core products? What are the synergies?

3. Which of the following roles does your company play in regard to the production and delivery of PMRS?

   - Research & Development YES/NO
   - Manufacturing YES/NO
   - Direct selling to end users YES/NO ____%
   - Sell to installers/contractors YES/NO ____%
   - Sell to PPAs YES/NO ____%

4. Could you describe the supply chain for your PMRS between your company and the end-user?

5. Who are your end users? Eg. large commercial, industrial. Are they financed by PPAs?

Sector	% Revenue	PPA?	Comments

6. Where are your markets for PMRS? And where are the other PMRS markets you're looking into?

Region	% Revenue	Comments

VIII. MARKET DRIVERS AND BARRIERS

For the next part, I'd like to ask you some questions about market drivers and barriers.

7. What are the main reasons for your customers to purchase a PMRS? (check all that applies)

- o Internal use -- optimize performance for energy management for *single* site _____%
- o Internal use -- optimize performance for energy management for *multiple* site _____%
- o PPA requirement _____%
- o Installer/contractor maintenance and support contract _____%
- o Required by the CSI _____%
- o Other reasons? ______________

8. How does the CSI affect your business? (check all that applies)

- o Create a market by requiring PMRS for large systems
- o CSI cost cap needs to be higher, by how much? ______
- o Others: ____________________

9. Is your company planning to continue the PMRS offering after the CSI program ends in 2017? How do you think the offering would change when CSI ends?

10. What are the main barriers in expanding the market or your market share?

IX. Customer Current Demand

11. In general, what are some features your customers are looking for? And what percentage of your customers looks for them?

Features	Must have (%)	Nice to have (%)
Minimum meter accuracy ______		
DC monitoring		
Performance benchmark		
Weather monitoring		
Multi-site monitoring		
Automated alerts by email or SMS (Customizable by user?)		
Communicate with HAN/BAS/EMS		

Communicate with smart meters		
User-friendly interface		

12. Specifically for the solar investors (eg. PPA), what are the minimum performance monitoring requirements?

Features	Must have (%)	Nice to have (%)
Minimum meter accuracy ______		
DC monitoring		
Performance benchmark		
Weather monitoring		
Multi-site monitoring		
Automated alerts by email or SMS (Customizable by user?)		
Communicate with HAN/BAS/EMS		
Communicate with smart meters		
User-friendly interface		

13. How does a minimum performance standard might affect the metering market?

14. How do these requirements affect the current price? And the price trends? (eg. will these requirements drive the costs down?)

X. SYSTEMS COSTS AND TRENDS

We're almost done. In the next part, I have a few questions on system costs.

15. What is the cost of your typical system? (Record range if appropriate)

- o Hardware
  - Meter
  - Communications
  - Weather station
- o Software

- o Installation
- o Annual service fee

16. What are the cost trends are you seeing in PMRS?

Costs	Change in 1 year	Change in 3 years
Meter	%	%
Communications	%	%
Weather monitoring	%	%
Software	%	%
Installation	%	%
Annual service fee	%	%

XI. TECHNOLOGICAL TRENDS

17. What are the technological trends are you seeing in PMRS? (eg. meter accuracy, communication systems, user interface etc)

18. What are the emerging innovations in PMRS? (integration with smart grid, EMS etc)

19. What are the main barriers in technological R&D?

20. Do you see that solar's integration with smart grid will be an important R&D area in the near future?

21. What are the barriers for integrating DG solar into smart grids?

22. Do you think solar will be fully integrated into smart grid in the near future? How long do you think it'll take?

23. In light of the recent federal energy stimulus, will your company be able to take advantage of it? How?

CSI Metering Market Survey – PMRS User

Interviewer:
Interviewee Name:
Interviewee Company:
Interviewee Title:
Date:
Time:

Hello. My name is ________________ from KEMA Consulting. I am calling on behalf of the California Public Utilities Commission regarding a comprehensive metering and monitoring study we're conducting under the California Solar Initiative.

I was referred to you by your PMRS provider. I have some questions for you (your company) related to your experience with your PMRS.

Are you the right person to speak to? [If no, ask for a referral and record his/her name and contact information: ____]

↳ [If hesitant] We understand that you are busy. However, this research is important to the industry and California's solar policies going forward.

For all the participants of this survey, we will send you a summary of our findings at the conclusion of this research.

If you wish, we can report all or part of the information you give us anonymously or in aggregate with other company's data.

[When agreed to participate] Great! This will take about 30 minutes.

[If not available now, schedule a time to talk within the same week _______________]

XIII. SYSTEM INFORMATION

Before I go into market trends, I'd like to ask you some background questions on your company and your solar system. Again, please tell me if you want part or all of your response be kept confidential.

1. What is the primary business at your solar site?

2. Can you describe your solar system?
    - Size
    - # inverters
    - # of meters
    - System configuration

3. How long have you had your PMRS? As long as you have your solar system?

4. How would you characterize your facility with the solar installation?
    - Number of buildings
    - Square footage
    - Energy usage
    - Energy management system?
    - PMRS connected to EMS?

5. If you don't do PMRS yourself, how is a PMRS provider chosen?

XIV. MARKET DRIVERS AND BARRIERS

For the next part, I'd like to ask you some questions about market drivers and barriers.

6. What are the main reasons for you to purchase a PMRS? (check all that applies)
    - Internal use -- optimize performance for energy management for *single* site
    - Internal use -- optimize performance for energy management for *multiple* site
    - Required by the CSI
    - Other reasons? _______________

7. How does the CSI affect your decision to purchase a PMRS? (check all that applies)

- o It's a requirement
- o Create a PMRS market, and eventually drive cost down?
- o CSI cost cap needs to be higher/lower, by how much? ______
- o Others: ____________________

8. Will you purchase a PMRS if it isn't a CSI requirement?

XV. Customer Current Demand

9. In general, what are some features you look for in PMRS?

Features	Must have	Nice to have
Minimum meter accuracy ______		
DC monitoring		
Performance benchmark		
Weather monitoring		
Multi-site monitoring		
Automated alerts by email or SMS (Customizable by user?)		
Communicate with HAN/BAS/EMS		
Communicate with smart meters		
User-friendly interface		

10. Is the current PMRS market providing what you need?

11. What are the gaps in the PMRS market/products?

12. Do you think there is an adequate number of PMRS providers in the market?

13. How satisfied are you with your PMRS product? (Please rate 1-5 with 5 being very satisfied). Explain.

14. Are you looking into upgrading your current PMRS? If so, what additional features are you looking for?

XVI. SYSTEMS COSTS AND TRENDS

We're almost done. In the next part, I have a few questions on system costs.

15. What is the cost of your typical PMRS system? (Record range if appropriate)
- o Hardware
  - ▪ Meter
  - ▪ Communications
  - ▪ Weather station
- o Software
- o Installation
- o Annual service fee

16. What do you think is a reasonable price for PMRS to be? Eg. in terms of % of total system cost.

XVII. TECHNOLOGICAL TRENDS (if familiar)

17. What are the technological trends are you seeing in PMRS? (eg. meter accuracy, communication systems, user interface etc)

18. What are the emerging innovations in PMRS? (integration with smart grid, EMS etc)

19. What are the main barriers in technological R&D?

20. Do you see that solar's integration with smart grid will be an important R&D area in the near future?

21. What are the barriers for integrating DG solar into smart grids?

22. Do you think solar will be fully integrated into smart grid in the near future? How long do you think it'll take?

XVIII. CLOSING

That's all the questions I have. Do you have any additional comments or questions?

To ensure the thoroughness of this research, who else would you recommend me to speak to?

I really appreciate your time today. If you think of any additional comments to give me or have questions about this study, please don't hesitate to contact me.

XII. CLOSING

That's all the questions I have. Do you have any additional comments or questions?

To ensure the thoroughness of this research, who else would you recommend me to speak to? Can we contact some of your customers? [Ask for customer contact name, phone and email]

I really appreciate your time today. If you think of any additional comments to give me or have questions about this study, please don't hesitate to contact me.

CSI Metering Market Survey – PPA Providers

Interviewer:
Interviewee Name:
Interviewee Company:
Interviewee Title:
Date:
Time:

Hello. My name is ________________ from KEMA Consulting. I am calling on behalf of the California Public Utilities Commission regarding a comprehensive metering and monitoring study we're conducting under the California Solar Initiative.

I have some questions for your company related to the metering market trends, eg. market drivers, barriers, demand, prices, and emerging technologies.

Are you the right person to speak to? [If no, ask for a referral and record his/her name and contact information: ____]

↳ [If hesitant] We understand that you are busy. However, this research is important to the industry and California's solar policies going forward.

For all the participants of this survey, we will send you a summary of our findings at the conclusion of this research.

If you wish, we can report all or part of the information you give us anonymously or in aggregate with other company's data.

[When agreed to participate] Great! This will take about 30 minutes.

[If not available now, schedule a time to talk within the same week _______________]

XIX. COMPANY INFORMATION

Before I go into market trends, I'd like to ask you some background questions about your company. Again, please tell me if you want part or all of your response be kept confidential.

1. Approximately how many systems do you install per year total and in CA?

2. How would you characterize your customers in CA?

Sector	% Revenue	PMRS (%)
Large commercial		
Gov't		
Industrial		

3. How does this characterization different than your customers nationwide?

4. Besides owning the systems, does your company provide any of the following?
    - o Installation
    - o Maintenance
    - o PMRS Service

5. If you don't provide PMRS yourself, how is a PMRS provider chosen? Do you normally partner with 1-2 PMRS providers?

XX. MARKET DRIVERS AND BARRIERS

For the next part, I'd like to ask you some questions about market drivers and barriers.

6. What are the main reasons for you to purchase a PMRS? (check all that applies)
    - o Internal use -- optimize performance for energy management for *single* site _____%
    - o Internal use -- optimize performance for energy management for *multiple* site _____%
    - o Required by the CSI _____%
    - o Other reasons? _______________

7. How does the CSI affect your business? (check all that applies)
    - o Create a market by requiring PMRS for large systems, and eventually drive cost down?
    - o CSI cost cap needs to be higher/lower, by how much? ______
    - o Others: ______________________

8. Will you continue to use (or provide) PMRS after the CSI ends in 2017?

9. What are the main barriers in expanding the PPA market or your market share?

XXI. Customer Current Demand

10. In general, what are some features you look for in PMRS?

Features	Must have (%)	Nice to have (%)
Minimum meter accuracy ______		
DC monitoring		
Performance benchmark		
Weather monitoring		
Multi-site monitoring		
Automated alerts by email or SMS (Customizable by user?)		
Communicate with HAN/BAS/EMS		
Communicate with smart meters		
User-friendly interface		

11. How does a minimum performance standard might affect the metering market?

12. How do these requirements affect the current price? And the price trends? (eg. will these requirements drive the costs down?)

13. Is the current PMRS market providing what you need to provide adequate confidence in securing your solar investments?

14. What are the gaps in the PMRS market?

15. Do you think there is an adequate number of PMRS providers in the market?

16. How satisfied are you with your PMRS product? (Please rate 1-5 with 5 being very satisfied). Explain.

XXII. SYSTEMS COSTS AND TRENDS

We're almost done. In the next part, I have a few questions on system costs.

17. What is the cost of your typical PMRS system? (Record range if appropriate)

- Hardware
  - Meter
  - Communications
  - Weather station
- Software
- Installation
- Annual service fee

18. What are the cost trends are you seeing in PMRS?

Costs	Change in 1 year	Change in 3 years
Meter	%	%
Communications	%	%
Weather monitoring	%	%
Software	%	%
Installation	%	%
Annual service fee	%	%

19. What do you think is a reasonable price for PMRS to be? Eg. in terms of % of total system cost.

20. How will the recent federal stimulus bill affect your business?

XXIII. TECHNOLOGICAL TRENDS

21. What are the technological trends are you seeing in PMRS? (eg. meter accuracy, communication systems, user interface etc)

22. What are the emerging innovations in PMRS? (integration with smart grid, EMS etc)

23. What are the main barriers in technological R&D?

24. Do you see that solar's integration with smart grid will be an important R&D area in the near future?

25. What are the barriers for integrating DG solar into smart grids?

26. Do you think solar will be fully integrated into smart grid in the near future? How long do you think it'll take?

XXIV. CLOSING

That's all the questions I have. Do you have any additional comments or questions?

To ensure the thoroughness of this research, who else would you recommend me to speak to? [Ask for customer contact name, phone and email]

I really appreciate your time today. If you think of any additional comments to give me or have questions about this study, please don't hesitate to contact me.

CSI Metering Market Survey – Research & Development

Interviewer:
Interviewee Name:
Interviewee Company:
Interviewee Title:
Date:
Time:

Hello. My name is ________________ from KEMA Consulting. I am calling on behalf of the California Public Utilities Commission regarding a comprehensive metering and monitoring study we're conducting under the California Solar Initiative.

I have some questions for your organization related to the metering market trends, eg. technology trends, market drivers and barriers.

Are you the right person to speak to? [If no, ask for a referral and record his/her name and contact information: ____]

↳ [If hesitant] We understand that you are busy. However, this research is important to the industry and California's solar policies going forward.

For all the participants of this survey, we will send you a summary of our findings at the conclusion of this research.

If you wish, we can report all or part of the information you give us anonymously or in aggregate with other company's data.

[When agreed to participate] Great! This will take about 30 minutes.

[If not available now, schedule a time to talk within the same week _______________]

XXV. COMPANY INFORMATION

Before I go into market trends, I'd like to ask you some background questions about your company. Again, please tell me if you want part or all of your response be kept confidential.

1. What is your organization working on in terms of solar PMRS?

2. What are the results so far? Can you point me to some of your reports?

3. What is driving your research in this area?

4. Are you partnering with any manufacturers in your R&D? Who are they?

5. Where does the funding come from?

6. How does the CSI affect your research trajectory? (check all that applies)

XXVI. TECHNOLOGICAL TRENDS

7. What are the technological trends are you seeing in PMRS? (eg. meter accuracy, communication systems, user interface etc)

Features	Trends
Minimum meter accuracy ______	
DC monitoring	
Performance benchmark	
Weather monitoring	
Multi-site monitoring	
Automated alerts by email or SMS (Customizable by user?)	
Communicate with HAN/BAS/EMS	
Communicate with smart meters	
User-friendly interface	

8. What are the emerging innovations in PMRS? (integration with smart grid, EMS etc)

9. What are the main barriers in technological R&D?

10. Do you see that solar's integration with smart grid will be an important R&D area in the near future?

11. What are the barriers for integrating DG solar into smart grids?

12. Do you think solar will be fully integrated into smart grid in the near future? How long do you think it'll take?

XXVII. SYSTEMS COSTS AND TRENDS

We're almost done. In the next part, I have a few questions on system costs.

13. What is the cost of your typical system? (Record range if appropriate)
    - Hardware
        - Meter
        - Communications
        - Weather station
    - Software
    - Installation
    - Annual service fee

14. What are the cost trends are you seeing in PMRS?

Costs	Change in 1 year	Change in 3 years
Meter	%	%
Communications	%	%
Weather monitoring	%	%
Software	%	%
Installation	%	%
Annual service fee	%	%

XXVIII. CLOSING

That's all the questions I have. Do you have any additional comments or questions?

To ensure the thoroughness of this research, who else would you recommend me to speak to?

I really appreciate your time today. If you think of any additional comments to give me or have questions about this study, please don't hesitate to contact me.

Appendix G: Solar Incentive Program Staff Interviewees

List of Interviewees from Section G –Comparison of Metering Requirements in Solar Incentive Programs

Program	Title	Name	*Date*
Sacramento Municipal Utility District	PV Program Manager	Jim Barnett	04/09/2009
City of Roseville	Solar Program Manager	Marty Bailey	03/04/2009
Los Angeles DWP	Electrical Engineering Associate, Solar power group	John Gutenberger	03/05/2009
City of Glendale	Senior Electrical Service Planner	Victor Pacheco	04/01/2009
NV Energy	Utility Engineer	Sachin Verma	04/01/2009
Public Service New Mexico	Photovoltaic Program Manager	Frank Andazola	03/04/2009
APS	Electric Shop Meter Leader	Mike O/Meara	03/04/2009
New Jersey SREC	Program Administrator	Nathalie Shapiro	03/02/2009
NY Dept of Public Service	Office of Consumer Services	Kenneth Resca	03/31/2009
NY Dept of Public Service	Power System Operations Specialist IV	Jason Pause	04/09/2009
MASS Energy	Energy Program Associate	Kelly Muellman	02/19/2009
Gainesville Feed-in Tariff	Gainesville Regional Utilities	Milvia Hidalgo	03/02/2009

Appendix H: PMRS Market Participant Interviewees

Category	Company	Name	Title	Date
Contractor	Conergy Projects	Zac McMordie David Vincent	Project Engineer Project Engineer	04/15/09
Contractor	Stellar Energy Solutions	Jason Larson	N/A	04/09/09
Contractor	Sullivan Solar Power	Quinn Laudenslager	Project Manager	04/08/09
Contractor	SunLight Electric	Rob Erlichman	President	04/09/09
PMRS	Draker Labortories	Adam Bouchard	Process Implementation Engineer	04/17/09
PMRS	Enphase	Ragthu Belur	VP Marketing	04/20/09
PMRS	Locus Energy	Michael Herzig	President	04/17/09
PMRS	N2 Electric, Inc.	Dave Drews	Founding Partner	04/15/09
PMRS	Pyramid Solar	Matt Kober	CEO	04/14/09
PMRS/ Contractor	Sunpower	Brock LaPorte	Director, Information Systems Business Marketing	04/23/09
PPA/ PMRS	enXco	Gonzalo Stabile	Director of Research and Development	05/01/09
PPA/ PMRS	Solar City	Ivan Cooper	Systems Monitoring Manager	04/30/09
PPA	Photon Energy	Dustin Keele	Executive VP and co-founder	04/24/09
PPA	Solar Power Partners	Brian Banke	Director of Asset Management	04/24/09
PPA	SunEdison	Mark Culpepper	CTO	05/05/09
PPA	SunRun	Susan Monson	Director of Operations	05/06/09

Category	Company	Name	Title	Date
PPA	Tioga Energy	Lauren Powers	Energy Systems Manager	04/29/09
R&D	CEC PIER	Gerry Braun	Renewables	04/22/09
R&D	NREL	Peter McNutt	Senior Engineer	04/23/09
Customer	Chung Tai Zen Center	Michael Sung	Volunteer	04/24/09
Customer	City of Palm Desert	Jane Stanley	Administrative Secretary	04/24/09
Customer	Lundberg Farms	Greg Turcotte	Environmentalist	04/23/09
Customer	San Francisco Airport	Greg McCarthy	Electrical Engineer	04/23/09
Customer	Santa Clara University	Chris Watt	Director of Utilities Department	04/23/09
Customer	Solar Energy International	Ian Woofenden	Northwest & Costa Rica Coordinator	04/24/09